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Review of New Source Performance Standards for Coal-Fired Utility Boilers. Volume I. Emissions and Non-Air Quality Environmental Impacts

Teknekron, Inc, Berkeley, Calif.

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Review of New Source Performance Standards for Coal-Fired Utility Boilers

Volume I
Emissions and Non-Air Quality Environmental Impacts

Interagency Energy/Environment R&D Program Report

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This two volume report summarizes a study of the projected effects of several different revisions to the current New Source Performance Standard (NSPS) for sulfur dioxide (SO_2) emissions from coal-fired utility power boilers. The revision is assumed to apply to all coal-fired units of 25 megawatts or greater generating capacity beginning operation after 1982. The revised standards which are considered are: (1) mandatory 90 percent SO_2 removal with an upper limit on emissions of 1.2 lb SO_2 per million Btu; (2) mandatory 80 percent SO_2 removal with the same upper limit; (3) no mandatory percentage removal with an upper limit of 0.5 lb SO_2 per million Btu. In addition, effects of revising the NSPS for particulate emissions from the current value of 0.1 lb per million Btu down to 0.03 lb are quantified. Projections of the structure of the electric utility industry both with and without the NSPS revisions are given out to the year 2000. Volume 1 discusses air emissions, solid wastes, water consumption, and energy requirements. Volume 11 discusses economic and financial effects, including projections of pollution control costs and changes in electricity prices.

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REVIEW OF NEW SOURCE PERFORMANCE STANDARDS FOR COAL-FIRED UTILITY BOILERS

VOLUME I: EMISSIONS AND NON-AIR QUALITY ENVIRONMENTAL IMPACTS

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PREFACE

This report is one of several volumes being submitted by Teknekron to the U.S. Environmental Protection Agency under contract 68-01-3970, "Review of New Source Performance Standards for Sulfur Dioxide Emissions from Coal-Fired Steam Generators." This volume presents the emissions and non air-quality environmental implications of alternative New Source Performance Standards as they will apply to the U.S. electric utility industry. Volume II discusses the economic and financial implications of the various SO_2 control alternatives described herein and is being submitted concurrently with this volume. A third volume discussing the air quality implications of the emissions control alternatives is anticipated, as is a final volume containing a series of "issue papers" summarizing results which bear on specific policy issues relating to EPA's proposal to revise the current standard.

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SUMMARY OF RESULTS

Several alternative New Source Performance Standards have been evaluated in terms of their implications for the U.S. electric utility industry. The projected development of the industry through the year 2000 under alternative NSPS for two different national electricity demand growth rates is discussed in Section 2 (moderate growth: 5.8% per year before 1985, 3.4% per year after 1985; high growth: 5.8% before 1985, 5.5% after 1985). The revised NSPS examined in this study are assumed to affect coal plants coming on line after 1982 with the current NSPS assumed to apply to plants coming on line between 1977 and 1982. Baseline scenarios with no revisions to the current NSPS have also been examined. The air emissions, solid wastes, water and energy requirements for each of these alternatives are presented in Section 3. Salient features of these results are summarized as follows:

- The U.S. electric utility industry will grow from 507 GW net capability in 1976 to about 750 GW in 1985 and to 1085 or 1310 GW in 1995 under the specified moderate and high growth rates, respectively.

- Given the coals selected for consumption by utilities as used in this analysis and the present SO_2 emission limitations, the installed flue gas desulfurization (FGD) capacity will amount to approximately 17 percent of net coal-fired generating capacity by 1985 and will remain at approximately that relative level for the following decade.

- In the high demand growth case under a revised NSPS requiring 80 percent post-combustion SO_2 removal and an emissions upper bound of 516 ng/J (1.2 lb/10^6 Btu) the installed FGD capacity will be 191 GW by 1990 and 351 GW by 1995. This compares to 59 GW in 1990 and 77 GW in 1995 under a continuation of the current NSPS.

- Increasing the SO_2 removal requirement from 80 to 90 percent will increase the installed FGD capacity by 10 to 15 percent by 1995, depending on the post-1983 growth rate. For the high growth case net coal-fired capability will be 580 GW nationally in 1995, FGD capacity about 403 GW.

- The regions of the country with the highest installed scrubber capacities by 1995, assuming a 90 percent SO_2 removal requirement, are West South Central (84 GW), East North Central (82 GW), and South Atlantic (76 GW). These three regions contain 60 percent of the total installed FGD capacity in 1995 in the high growth case.

- Utility coal consumption will increase from 404 million metric tons (445 million U.S. tons) in 1976 to about 910 million metric tons in 2000 for the moderate growth case or to 1670 million metric tons in 2000 for the high growth case.

- National emissions of SO_2 from all electric power plants will increase from 1976 partial compliance levels (about 13.6 million metric tons) at about two percent per year until 1985, if electricity demand grows at 5.8 percent per year.

- Under high demand growth after 1985 (5.5 percent per year in total demand and roughly six percent per year in coal-fired generation) national SO_2 emissions under current standards will increase at approximately 2.5 percent per year. A revised NSPS with 90 percent required removal will slow this growth in national SO_2 emissions to less than 1 percent per year between 1985 and 2000.

- Under moderate demand growth and present emission standards national SO_2 emissions will increase at approximately 0.4 percent per year from 1985 to 2000. A revised NSPS with 90 percent removal will bring about a net decrease in national SO_2 emissions after 1985. By the year 2000 national SO_2 emissions will be approximately equal to or below the 1976 partial compliance level for SO_2 emissions.

- In 1995 SO_2 emissions in the high demand case will be reduced from the baseline projections (current NSPS) by 17 percent for mandatory 80 percent post-combustion removal and by 27 percent for mandatory 90 percent post-combustion removal. In 2000 the reduction of national SO_2 emissions is projected to be 35 percent with 90 percent removal, 21 percent with 80 percent removal.

- A reduction in the electricity demand growth rate after 1985 to 3.4 percent per year along with a continuation of the current NSPS SO_2 standard will result in a national SO_2 emissions level in 2000 comparable to the level of emissions achievable under a 5.5 percent per year demand growth rate after 1985 with the 90 percent SO_2 removal standard. There are, however, regional differences in the distribution of emissions in these cases.

- In all years the predominant source of SO_2 emissions will be those units subject to SIP (State Implementation Plan) emission limits. Seventy-three percent of SO_2 emissions in 1995 in the moderate growth case will be due to SIP plants (those plants on line prior to 1977), six percent due to plants on-line between 1977 and 1982 (subject to the current NSPS) and 21 percent due to plants on-line after 1982 (those plants assumed to be subject to a revised NSPS).

- The revised SO_2 standards will have the greatest relative impact in those regions which do not presently have a large base of coal-fired generation. In 1990 a 90 percent removal standard under high growth reduces national SO_2 emissions by 3.3 million metric tons (19 percent). The West South Central region (56 percent), North Mountain region (53 percent), South Mountain region (47 percent), Pacific region (42 percent) and the New England region (23 percent) have the greatest percentage emissions reductions over current NSPS. In terms of tonnages, the West South Central, East North Central, and South Atlantic regions have the largest SO_2 emissions reductions.

- Given the coal sulfur levels used in this analysis the amount of SO_2 emitted under the 80 percent removal standard and the 215 ng/J (0.5 lb/10^6 Btu) standard are nearly the same in most regions. Nationally emissions differ at most by four percent. In the Mountain states where relatively low sulfur coals are used, the 80 percent removal requirement further reduces SO_2 emissions by about 30 percent in 2000.

- Assuming the moderate growth rate, total particulate emissions will increase only slightly above the 1980 full compliance level (0.8 million metric tons per year) and will remain nearly constant thereafter. High demand

growth would lead to further growth in particulate emissions in the 1990s, to about 1.1 million metric tons per year.

- Revising the NSPS for particulates downward to 13 ng/J (0.03 lb/10^6 Btu) from 43 ng/J (0.10 lb/10^6 Btu) reduces national aggregate emissions by 11 percent in 1990 and 22 percent in 2000. Particulate emissions from post-1982 units will be reduced by a greater percentage, which may have important local impacts.

- Emissions of NO_x from electric power generation will increase substantially under current standards, even assuming an effective electricity demand conservation program. Under high demand growth NO_x will increase from 5.7 million metric tons in 1980 to 15.6 million metric tons in 2000; under moderate demand growth to 8.6 million metric tons in 2000.

- Under the high growth case the tons of sludge on a dry basis generated by FGD systems will be 12 million metric tons nationally in 1995 for the current NSPS, 46 million metric tons for an 80 percent removal standard and 55 million metric tons for a 90 percent removal standard.

- The cumulative land area required to a depth of nine meters for disposal of this FGD sludge between 1990 and 2000 will be 15.1 km^2 (5.8 mi^2) and 91.5 km^2 (35 mi^2) for the current NSPS and the 90 percent removal standard, assuming high growth.

- Total coal ash production in 1995 will be 101 million metric tons about eight percent by weight of total coal burned. Between 1990 and 2000 cumulative storage of this ash to a depth of nine meters would require 176 km^2 (67.8 mi^2).

- Assuming full scrubbing of all post-1982 coal-fired units national water consumption by FGD systems is estimated to be 387 million cubic meters in the year 2000 in the moderate demand growth case, and 927 million cubic meters with higher growth. In comparison the rate of water consumption by generating plant cooling systems is twenty-two times the consumptive rate projected for scrubbers. Whether or not these water demands constitute a significant impact will depend on regional and local conditions.

- Direct energy consumption by FGD systems in 1995 will increase from less than one percent of the total Btu input for coal-fired generation under the current NSPS to as much as 3.8 percent under a 90 percent removal standard.

- Fuel consumed in transporting coal will be reduced with the imposition of more stringent controls, primarily due to a shifting of demand away from western coals delivered to states bordering and east of the Mississippi River. The energy savings in 1995, 50×10^9 MJ (4.7×10^{13} Btu) and 120×10^9 MJ (1.1×10^{14} Btu), are about 10 percent of the direct FGD energy requirements projected for that year, (588×10^9 MJ and 1150×10^9 MJ) in the moderate and high growth cases, respectively.

Details of Teknekron's analysis of alternative New Source Performance Standards are presented in the following sections.

1.0 INTRODUCTION AND BACKGROUND

This study reviews for the Environmental Protection Agency several alternative standards of performance for sulfur dioxide (SO_2) emissions from coal-fired electric generating units. Teknekron's analysis has included the following elements:

- Projections of the physical configuration and economic state of the electric utility industry to the year 2000
- Estimates of the costs of meeting different revised standards
- Calculations of the changes in sulfur dioxide and other emissions resulting from compliance with revised standards
- Corresponding air quality changes
- Identification and illumination of the major issues involved in weighing the relative benefits of different revisions

The basic tools used to provide quantitative data were Teknekron's Utility Simulation Model, a large-scale computer model which simulates the response of the electric utility industry to specified economic conditions, energy policies, and regulatory constraints, and Teknekron's Air Quality Impact Assessment Model, which links the emissions to the atmosphere, as projected by the Simulation Model, to ambient air-quality changes. Detailed descriptions of the Simulation Model are available elsewhere:[1] a brief description is given in the appendix to this volume. The air quality modeling process will be described in an anticipated third volume of this report.

1.1 BASE YEAR DATA

The results presented here were projected from a data base containing a description of every electric generating unit (nuclear, oil and gas-fired, hydro, geothermal and combustion turbine, as well as coal-fired) operating as of

31 December 1975, plus announced plans for new units through 1986. Beyond 1986, the model creates new generating units and sites them by county as needed to meet projected demand. In order to simulate the industry's response to a pollution control regulation, including a particular new source performance standard (NSPS) for SO_2 emissions from coal-fired units, a minimum set of "scenario parameters" must be specified. Key among these are:

- The future growth rate in peak and average power demand
- "Future mix fractions" for each state, giving the breakdowns of new generating capacity beyond 1985 by type of generation
- The kinds of coal to be burned by each coal-fired unit, including sulfur and ash content

Other non air-pollution related variables which must be specified include an overall inflation rate, new plant construction costs, costs of water pollution controls, assumptions about the rate of phase-out of natural gas as a utility boiler fuel, the minimum generating reserve margin to be maintained, the size and thermal efficiency of future generating units, fuel prices and price trends, and the order in which each utility system will "dispatch" the available units in order to meet the projected demand.*

Variables which relate directly to the costs and effectiveness of air pollution controls include specification of the sulfur dioxide (SO_2), particulate, and nitrogen oxide (NO_x) emission limits that must be met by both old and new units and the costs of the pollution-control devices used to insure compliance (flue gas desulfurization (FGD) systems, electrostatic precipitators and fabric filters, modified boiler configurations for NO_x control), and constraints on siting future

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* A "utility" in the model is formed by merging data from all investor owned and all publicly owned utilities within each state, so that there are at most two "utilities" per state. These are referred to as "state firms."

units due to air quality considerations. Much of these data – e.g., the demand projections, future mix fractions, and coal assignments – vary state by state. Others, such as the parameters used in the pollution control cost models, are uniform nationally – although the emission limits which the control devices must be designed to meet may vary by state – in fact by county.

The basic categories of results which the simulation produces are:

1. Economic and financial impacts at the state level
   - Capital requirements for new generating units and for pollution controls
   - Electricity prices and utility revenues
   - Utility operating costs
   - Return on utility equity
2. Industry composition and fuel consumption down to the county level
   - Generating mix
   - Fuel consumption
   - Reserve margins and capacity factors
3. Environmental residuals at the county level
   - Emissions of SO_2, NO_x, and particulates to the atmosphere*
   - Solid wastes (mainly FGD sludge)
   - Water consumption for condenser cooling, coal cleaning, and FGD makeup

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* Emissions of twelve trace elements are also calculated, but these have not been analyzed in this study.

1.2 SPECIFICATION OF SCENARIOS

The set of key input variables which must be specified before a simulation can be run collectively define one "scenario" for which estimates of costs and environmental benefits can be quantified. These variables can reflect both broad national policies such as those outlined in the President's National Energy Plan[2], or very region-specific assumptions such as the fraction of post 1985 base-load generating capacity in a particular state that will be nuclear. The key assumptions which are common to all scenarios analyzed to date are summarized in Table 1–1.

Assumptions about State Implementation Plan (SIP) standards, although invariant among scenarios, are critical in defining the "baseline" emission levels against which changes due to the NSPS revisions are to be measured. The SIP limits for coal-fired units that were used in this analysis were based on unit-by-unit data supplied by EPA's Office of Planning and Evaluation in August 1977. Some simplifications to the data were made. First, those limits which varied within a state were simplified to only two values, a more stringent limit, referred to as a "Metropolitan SIP", and a less stringent limit, referred to as a "Non-Metropolitan SIP". All counties within each state were so designated. The numerical limits were chosen to approximate the means of the generally bi-modal distribution of actual SIP limits within states. Second, judgment was used to convert those limits which were expressed in terms of concentrations of SO_2 in the stack gas, or ambient air concentrations, into equivalent emission rates (nanograms per joule or pounds per million Btu). Third, limits for several western states were tightened below those currently being applied to reflect EPA's judgments about probable SIP revisions due to "prevention of significant deterioration" and attempts to protect visibility in the relatively pristine western regions. As a result, there are several western states in which the SIP limits for SO_2 emissions are more stringent than the current new source standard. In these cases the SIP takes precedent: i.e., it is applied to all affected units coming on-line before 1983. Tables 1–2 and 1–3 give the SIP SO_2 limits and county

Table I-1

Key Scenario Elements Held Constant Throughout the Analysis

Air Pollution Regulations:	State Implementation Plan emission standards (as of 8/77) for SO_2 and particulates applied to all units on-line before 1977. Full compliance assumed by 12/31/79.
	Current (1977) NSPS for fossil-fueled units applied to all units on-line between 1977 and 1982. Values for coal are: 516 ng/J (1.2 lb/10^6 Btu) for SO_2, 43 ng/J (0.1 lb/10^6 Btu) for particulates, and 301 ng/J (0.7 lb/10^6 Btu) for NO_x. Compliance assumed at inception.
Siting Restrictions:	Coal and oil-fired units beyond those already announced are excluded from any county containing a portion of an Air Quality Control Region qualifying for Mandatory Class I or Non-Attainment status.[a]
Conversions and Rerates:	Conversions from oil and gas to coal, as per Prohibition Orders issued by the Federal Energy Administration as of June 30, 1977, are assumed effected by 1985.[b] Additional gas phase-outs based upon FEA estimates published in 1975 are also included. All gas-fired units are retired by 1996.
	No new oil or gas-fired generating capacity is built after 1984.
	Announced uprates, derates, and retirements as per FPC Order 383-4, 1 April 1977.
Water Pollution Regulations:	Full compliance with chemical and thermal emission limits promulgated for the steam electric power industry in 1974 is assumed by 1977 and 1981, respectively.
Populations:	Census Bureau Series II Projections.[3]

a Mandatory Class I areas are defined in accordance with the Clean Air Act Amendments of 1977: wilderness areas and memorial parks exceeding 5,000 acres, national parks exceeding 6,000 acres. Non-attainment areas are those counties with a recorded violation of any National Ambient Air Quality Standard in 1975.

b Oil and gas-fired units which began operation before 1977 but convert to coal in 1977 or later are assumed to be subject to the applicable SIP coal limit, not the NSPS.

Table I-2

SIP SO_2 Emission Limits for Coal-Fired Units Used in the NSPS Scenarios

(Pounds SO_2 per million Btu heat input)

STATE	Met SIP	Non-Met SIP
Alabama	1.8	4.0
Arizona	0.34	0.34
Arkansas	1.2	1.2
California	0.8	4.7
Colorado	0.2	0.2
Connecticut	0.8	0.8
Delaware	1.6	No Limit
Florida	1.5	6.2
Georgia	0.56	5.3
Idaho	1.6	1.6
Illinois	1.8	6.0
Indiana	1.2	No Limit
Iowa	5.5	5.5
Kansas	3.0	No Limit
Kentucky	1.2	5.7
Louisiana	4.2	4.2
Maine	2.4	4.0
Maryland & D.C.	1.6	1.6
Massachusetts	1.1	2.7
Michigan	2.0	2.0
Minnesota	3.2	4.2
Mississippi	2.4	4.8
Missouri	2.9	6.4
Montana	2.0	2.0

Table I-2
(Continued)

STATE	Met SIP	Non-Met SIP
Nebraska	2.5	2.5
Nevada	0.2	0.2
New Hampshire	4.7	4.7
New Jersey	0.32	1.6
New Mexico	0.34	1.4
New York	0.4	4.3
North Carolina	1.6	1.6
North Dakota	3.0	3.0
Ohio	1.4	4.5
Oklahoma	2.0	2.0
Oregon	2.1	2.1
Pennsylvania	0.7	3.0
Rhode Island	1.1	1.1
South Carolina	2.3	3.5
South Dakota	3.0	3.0
Tennessee	1.2	4.4
Texas	2.0	2.0
Utah	0.2	0.2
Vermont	1.6	1.6
Virginia	1.4	3.5
Washington	3.3	3.3
West Virginia	2.8	2.8
Wisconsin	2.0	2.0
Wyoming	0.2	0.2

Table I-3

County Designations

STATE	Met Counties	Non-Met Counties	No Differentiation
Alabama	AQCR #5 Jefferson County Jackson County	AQCR 1, 2, 3, 4, 6 + Colbert, Cullman, Dekalb, Franklin, Lauderdale, Lawrence Limestone, Madison, Marion, Marshall, Morgan and Winston Counties	
Arizona			X
Arkansas			X
California	AQCRs #27,28,30 25, 32, 24, 29, 33 and 23	AQCRs #31 and 26	
Colorado			X
Connecticut			X
Delaware	New Castle County	All others	
Florida	Escambia, Duval and Hillsborough Counties	All others	
Georgia	Dougherty, Chatham, Cobb, Camden, Bibb, Cherokee and Fulton Counties	All others	
Idaho			X
Illinois	AQCR #65, 67, and 70	All others	
Indiana	All others	Greene, Clinton, Cass and Sullivan Counties	
Kansas	AQCR #94, 95, and 96	AQCR #97, 98, 99, and 100	

Table I-3
(Continued)

STATE	Met Counties	Non-Met Counties	No Differentiation
Kentucky	AQCR #78 and McCracken County	All others	
Louisiana			X
Maine	AQCR #110	AQCR #107, 109	
Maryland & D.C.			X
Massachusetts	AQCRs #118, 120, and Suffolk County	All others	
Michigan			X
Minnesota	AQCR #131	All others	
Mississippi	Washington and Harrison Counties	All others	
Missouri	AQCR #70	All others	
Montana			X
Nebraska			X
Nevada			X
New Hampshire			X
New Jersey	All others	Atlantic, Cape May Cumberland, Hunterdon, Ocean, Sussex, and Warren Counties	
New Mexico	AQCR #14	All others	
New York	Bronx, Kings, Queens, New York, Nassau, Rockland, Westchester, Richmond and Suffolk Counties	All others	

Table I-3
(Continued)

STATE	Met Counties	Non-Met Counties	No Differentiation
North Carolina			X
North Dakota			X
Ohio	Muskingum, Clermont, Ashtabula, Greene, Richland, Allen, Ottowa, Stark, Wood, Adams, Hamilton, Butler, Montgomery, Lake, Cuyahoga, Morgan, Franklin, and Lorain Counties	All others	
Oklahoma			X
Oregon			X
Pennsylvania	Beaver, Hancock, Brook, Washington, Allegheny, Westmoreland, Somerset, Cambria, Blair, Perry, Cumberland, Adams, York, Dauphin, Lancaster, Chester, Delaware, Montgomery, Bucks, Lehigh, Northhampton, Luzerne, Lackawanna, Susquehanna, Philadelphia, and Armstrong Counties	All others	

Table I-3
(Continued)

STATE	Met Counties	Non-Met Counties	No Differentiation
Rhode Island			X
S. Carolina	Charleston, Aiken, and Anderson Counties	All others	
S. Dakota			X
Tennessee	Humphreys, Polk, Maury, Sullivan, and Roane Counties	All others	
Texas			X
Utah			X
Vermont			X
Virginia	AQCR #47	All others	
Washington	Wahtcom, Skagit, San Juan, and Island Counties	All others	
West Virginia			X
Wisconsin			X
Wyoming			X

designations which were used for coal-fired units in this study. Limits for particulate and for oil-fired units were not changed from those used in Teknekron's earlier modeling work for EPA.[2]

The key elements which vary among the scenarios are the assumed growth rate in demand for electricity and the revised NSPS being analyzed, the latter being applied only to coal-fired units of at least 25 Mw on-line in 1983 or later. Table 1–4 summarizes the two sets of demand growth scenarios which were considered.

The revised NSPS which were considered involve one change in the particulate and NO_x standards, combined with three different SO_2 standards:

SO_2

1. Ninety percent mandatory post-combustion SO_2 removal with an upper limit ("cap") on emissions of 516 ng/J (1.2 lb/10^6 Btu).
2. Eighty percent mandatory post-combustion SO_2 removal with an upper limit on emissions of 516 ng/J (1.2 lb/10^6 Btu).
3. No mandatory percentage post-combustion SO_2 removal, with an upper limit on emissions of 215 ng/J (0.5 lb/10^6 Btu).

Particulates No mandatory percentage removal, with an upper limit on emissions of 12.9 mg/J (0.03 lb/10^6 Btu).

NO_x No mandatory percentage removal, with an upper limit on emissions of 258 ng/J (0.6 lb/10^6 Btu).

Both the demand growth assumptions and the candidate NSPS revisions were specified by the Environmental Protection Agency. The "moderate" growth cases are meant to reflect a successful energy conservation effort as envisioned by the

Table I-4

National Electricity Demand Growth Rates

(percent per year)

	1975–1985		1986–2000	
	Peak	Average	Peak	Average
"Moderate" Growth	5.8	5.8	3.4	3.4
"High" Growth	5.8	5.8	5.5	5.5

National Energy Plan. (Our assumptions about natural gas phase-outs and oil and gas conversions to coal are also designed to reflect the goals of the N.E.P.) Additional scenarios in which we impose no Clean Air Act related air pollution regulations are also contemplated: these will be used to calculate the <u>total</u> cost of air pollution control as opposed to the <u>incremental</u> costs incurred in complying with a revised new source performance standard.

The nomenclature used to label results from the nine different scenarios presented is as follows: the letter "M" or "H" first indicates "moderate" or "high" electric demand growth. This is followed by three numbers which specify the SO_2 emission "cap" (in $lb/10^6$ Btu), the required percent SO_2 removal, and the particulate limit (in $lb/10^6$ Btu). Since the NO_x limit was set at 258 ng/J (0.6 $lb/10^6$ Btu) in all cases except the "baseline" scenarios (no NSPS revisions), its value is not indicated explicitly. The scenarios are summarized in Table I–5.

Table 1-5

Alternative NSPS Scenarios

Scenario Label	Revised NSPS in lb/10^6 Btu (% Removal)
M1.2(0)0.1 (Baseline with moderate growth)	SO_2 = 1.2 (0) NO_x = 0.7 Particulates = 0.1
H1.2(0)0.1 (Baseline with high growth)	Same as above
M1.2(90)0.1	SO_2 = 1.2 (90) NO_x = 0.6 Particulates = 0.1
H1.2(90)0.1	Same as above
M1.2(90)0.03	Same as M1.2(90)0.1 but with Particulates = 0.03
H1.2(90)0.03	Same as H1.2(90)0.1 but with Particulates = 0.03
M1.2(80)0.03	SO_2 = 1.2 (80) NO_x = 0.6 Particulates = 0.03
H1.2(80)0.03	Same as above
M0.5(0)0.03	SO_2 = 0.5 (0) NO_x = 0.6 Particulates = 0.03

2. INDUSTRY PROJECTIONS

This chapter sets the stage for the simulations by first characterizing the utility industry* in the base year (1975), and then projecting that configuration forward in time. The characteristics which we focus on are the capacity mix, i.e. aggregate generating capacity broken down by type of generation (coal, oil, nuclear, etc.), the distribution of generating units by regulatory category (SIP, NSPS, or revised NSPS), and the amount of capacity using FGD.

Because the Utility Simulation Model takes into account many of the complex interactions which occur among utilities' pollution control compliance strategies and their other planning and dispatching decisions, projections of characteristics like capacity mix are not independent of the particular pollution control scenario being considered. To illustrate, a decision to comply with an SO_2 emission limit through use of FGD will result in a generating capability reduction which must eventually be compensated for somewhere in the system. If that utility system's reserve margin is ample, then the lost capacity can be compensated for in the short term by running the existing units at higher levels. If the reserve is already near the safe minimum, however, the utility must plan for increased capacity additions, either by building more combustion turbines in the short term, or accelerating planned building schedules in the longer term. Regardless of the particular system, more capacity will have to be added in the long run if a substantial number of units are forced to use FGD because of a new air emissions regulation. Fuel consumption as well varies with emissions control strategy. For example, increased use of FGD in the Midwest and East will tend to encourage the use of locally available medium and high sulfur coals at the expense of more distant supplies of low sulfur western coal. This in turn changes the average heating value of the fuel, resulting in a change in the tonnage of coal burned by

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* The investor owned sector and the publicly owned sector (municipal systems plus the Tennessee Valley Authority and other federal projects) are treated together in this volume. Differences between these sectors from a financial perspective are discussed in Volume II.

the industry.* Such interactions are important characteristics of the electric utility industry which cannot be ignored in a realistic assessment of "the costs of pollution control." Unfortunately, they also make comparisons among scenarios more difficult, because several variables that influence costs may be changing simultaneously.

2.1 CAPACITY MIX IN THE BASE YEAR

Table 2-1 defines the geographical regions used in reporting capacity mix and other industry characteristics. Table 2-2 shows the electrical generating capacity as of December 1975 included in Teknekron's data base. Two key scenario variables involved in projecting this base-year capacity mix to any future year are the electrical demand growth rates that apply to each region, and the future fractions used in adding new units once the files of announced units for a given state have been exhausted. State-level growth rates are scaled from the national average values shown in Table 1-4 according to population growth. States whose growth is projected to be higher or lower than the national level will have higher or lower demand growth rates, respectively, with the scaling being done so as to maintain the originally specified national energy demand (or average power) growth.** Average compound growth rates for the periods 1976-1985 and 1986-1995 derived by this process are given in Table 2-3.

There is no tractable decision rule for predicting the proportions of future units built beyond 1985 which will be nuclear or coal. Future-mix fractions for each state firm are therefore specified exogenously to the model. These may be made to vary with the emissions control scenario, or held constant. In accordance with

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* The amount of coal that must be burned to yield one kilowatt-hour of electrical energy is given by the unit's heat rate (a way of expressing thermal conversion efficiency) divided by the coal's heating value. It takes about one pound of coal to produce one kilowatt-hour from a modern coal-fired boiler. Variations in tonnage burned among the control scenarios described here were not significant.

** A national peak growth rate has less physical meaning since the time of peak power demand varies widely across the country.

Table 2-1

Definition of Geographic Regions

New England (NE)	Mid-Atlantic (MA)	S. Atlantic (SA)	E.N. Central (ENC)
CT	NY	DE	WI
RI	PA	MD/DC	MI
MA	NJ	VA	IL
NH		WV	IN
VT		NC	OH
ME		SC	
		GA	
		FA	

E.S. Central (ESC)	W.N. Central (WNC)	W.S. Central (WSC)
KY	ND	TX
TN	SD	OK
MS	NB	AR
AL	KS	LA
	IA	
	MO	
	MN	

N. Mountain (NM)	S. Mountain (SM)	Pacific (PA)
ID	NV	WA
MT	UT	OR
WY	CO	CA
	AZ	
	NM	

NOTE: The first seven and the last region are identical to the Bureau of the Census regions.

Table 2-2

Utility Industry Generating Capacity as of December 31, 1975[a]

(Gigawatts)

Region[b]	Nuclear	Coal	Oil	Gas	Hydro	Combustion Turbine	Other[c]	Total
NE	5.0	0.6	11.5	0.03	2.5	1.1	0.4	**21.1**
MA	10.5	18.5	22.3	0.04	6.7	10.4	0.2	**68.6**
SA	8.5	46.3	17.8	1.6	6.0	8.0	0.8	**89.0**
ENC	8.8	62.2	4.8	1.7	3.1	4.4	2.3	**87.3**
ESC	2.1	27.9	1.3	2.9	5.9	0.5	2.2	**42.8**
WNC	3.4	13.2	0.2	6.3	3.1	3.0	1.1	**30.3**
WSC	0.8	2.6	3.2	50.1	2.3	1.8	0.2	**61.0**
NM	0.	3.9	0.07	0.02	2.9	0.	0.1	**7.0**
SM	0.	13.3	1.4	2.7	3.1	1.1	0.6	**22.2**
PA	2.3	1.4	19.1	3.0	30.0	1.1	0.7	**57.6**
Nation	**41.4**	**189.9**	**81.7**	**68.4**	**65.6**	**31.4**	**8.6**	**487.0**

a Average of summer and winter capabilities. The total is 96% of the name-plate capacity reported by the Edison Electric Institute.[4]

b See Table 2-1 for definitions.

c Geothermal + combined cycle + internal combustion (diesel) generators.

Table 2-3

Scaled Energy Demand Growth Rates, by Region

(Average compound growth rate in percent per year)

	"Moderate" Growth Scenarios		"High" Growth Scenarios	
REGION[a]	1976–1985	1986–1995	1976–1985	1986–1995
NE	5.6	3.4	5.6	5.5
MA	5.5	3.3	5.5	5.4
SA	6.2	3.7	6.2	5.9
ENC	5.6	3.3	5.6	5.4
ESC	6.0	3.4	6.0	5.5
WNC	5.2	3.0	5.2	5.1
WSC	5.6	3.3	5.6	5.4
NM	4.6	2.8	4.6	4.8
SM	6.3	3.8	6.3	5.9
PA	5.7	3.4	5.7	5.5
Nation	5.8	3.4	5.8	5.5

[a] See Table 2-1.

EPA's directives, the fractions used in deriving the results presented here were supplied to Teknekron by ICF, Inc., another contractor supporting EPA's study.[5] (Coal assignments and coal-unit dispatch orders, by regulatory category, were also taken from data supplied by ICF.) The approach used by ICF was to hold the amount (megawattage) of nuclear capacity in 1995 constant – i.e. independent of both the post-1985 growth rate and the control scenario. The rationale used to justify keeping the nuclear capacity the same under the moderate and high growth cases is that a variety of regulatory and other constraints are operating which would hinder the acceleration of nuclear building schedules beyond those currently envisioned by 1990, and that the amount of building we are assuming is already set at an "optimistic" level. The reason for not attempting to quantify the shift to nuclear that might occur as a result of the imposition of more stringent emission standards on coal units beyond 1990 is related: we feel that this issue is too complex to model realistically, at least within the context of the current study, because: (1) many of the important determinants of a utility's decision whether to "go nuclear" are not quantifiable (e.g., the expected licensing period); (2) those measures which are in principle quantifiable, such as relative power generating costs, are impossible to predict accurately in the 1990 time frame due to great uncertainties in the cost data. (This issue is discussed more fully in Volume II, "Economic and Financial Impacts".)

2.2 PROJECTIONS TO 2000

Capacity mixes for the two baseline scenarios (M1.2(0)0.1 and H1.2(0)0.1) and the two 90 percent control scenarios (M1.2(90)0.1 and H1.2(90)0.1) are shown in Table 2-4. Note that although the total capacity in 1995 does not vary when the more stringent SO_2 controls are imposed, there is a slight increase in nuclear capacity with a corresponding decrease in coal-fired capacity. Note again that this shift is <u>not</u> due to conclusions about the relative economics of coal vs. nuclear generation in the future. One factor which does operate is that capacity penalties incurred when FGD systems are applied to coal-fired units, are, over

Table 2-4

Projected Capacity Mix for Selected Scenarios

(Net capability, Gigawatts)

	1985				1995				Additions (1977-1995)			
	a	A	b	B	a	A	b	B	a	A	b	B
Coal	285.	283.	285.	284.	417.	403.	601.	589.	219.	204.	403.	390.
Oil & Gas	159.	159.	159.	159.	125.	125.	125.	125.	-32.3	-32.3	-32.3	-32.3
Comb. Cycle	8.00	8.00	8.00	8.00	8.00	8.00	10.6	10.7	6.80	6.80	9.40	9.50
Hydro	86.1	86.1	86.1	86.1	87.9	86.2	90.5	86.5	20.5	18.8	23.1	19.1
Turbine	68.8	69.0	68.9	68.8	78.1	80.0	101.	108.	36.2	38.1	59.0	66.0
Geothermal	1.70	1.70	1.70	1.70	1.90	1.90	1.90	1.90	1.60	1.60	1.60	1.60
Nuclear	138.	138.	137.	139.	365.	378.	379.	387.	358.	338.	339.	347.
TOTAL	747.	745.	746.	747.	1083.	1082.	1309.	1308.	610.	575.	803.	801.

Legend: a = MI.2(0)0.1 (Moderate growth baseline)
A = MI.2(90)0.1/0.03 (Moderate growth, 90 percent SO_2 removal on post-1982 units, either particulate limit)
b = HI.2(0)0.1 (High growth baseline)
B = HI.2(90)0.1/0.03 (High growth, 90 percent SO_2 removal on post 1982 units, either particulate limit)

the long term, partially compensated for by increased nuclear capacity. Note that the tabular values are net "capability," i.e., generating capacity after reducitons due to all pollution control devices are taken into account: these may amount to as much as ten percent of the "name-plate" capacity. If name-plate values were shown, the values for coal capacity under the more stringent controls scenarios would increase by roughly five percent in 1995. Since nuclear units have only water pollution controls, the name-plate capacities of the nuclear units are greater by a smaller fraction, and that fraction is independent of the SO_2 controls assumed.

Two other aspects of the planning algorithms used by the model to create new capacity once the announcements data file for a given state has been exhausted bear upon the amount of nuclear capacity added in the 1990s.* New base-load units are added in discrete sizes, not in the exact amount of capacity needed to bring the reserve margin up to the minimum.** Secondly, the specified future fractions are applied in a probabilistic sense. For example, specifying that 70 percent of the post-1985 capacity built in a New England state will be nuclear is interpreted by the model as a seven out of ten probability that a new unit will be nuclear. As a result, the exact amount of nuclear capacity installed by any year beyond 1985 cannot be "clamped" exogeneously. While this reflects planning uncertainties in the real world, it does compiicate the process of isolating the impacts of changing standards applied to fossil-fueled units. Aggregate nuclear capacity can be adjusted by trial and error; this was in fact done for the H1.2(90)0.03 scenario, in which the initial model runs produced higher nuclear values than shown in these results.

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* Announced units are not necessarily put into operation at the date the utility has projected: units are deferred if the specified demand growth does not justify operation until a later date. We assume, however, that steam plant construction schedules may not be accelerated and that combustion turbines will be built in the short term, if demand requires and if more announced units are planned for a later year.

** The simulated sizes are: nuclear – 1,200 Mw, coal – 600 Mw, oil – 500 Mw.

Table 2-5 shows capacity mix by geographic region for the baseline scenario with moderate growth (M1.2(0)0.1). The last column gives the capacity additions over the years 1985-1995, the period over which new builds are determined primarily by the future-mix fractions.

The age distribution of coal-fired units is important in this study because we apply the revised new source standards only to those units that came into commercial operation in 1983 or later.* The following summarizes the key dates used to categorize all fossil-fired units by applicable emission standard:

Year On Line	Applicable Category of Emission Standards
1976 or earlier	State Implementation Plan (SIP)
1977-1982	New Source Performance Standards (NSPS)
1983 or later	Revised New Source Performance Standards

Table 2-6 gives the age breakdown, by category in five year intervals from 1980 to 1995. In 1985, the first year for which we will be discussing emission changes due to a NSPS revision, the fraction of coal-fired capacity affected is only 11.5 percent. In the lower growth rate case, less than half of the coal-fired capacity would be subject to the revised standard by 2000, the last year of the simulation. With higher growth, the fraction affected in that year is 69 percent.

* The Clean Air Act stipulates that the revised standard will apply to those units whose construction commences after publication of the proposed revision. The definition of "commence construction" is somewhat at issue, and construction periods vary: we assume a fixed year of implementation, 1983.

Table 2-5

Projected Capacity Mix, by Region, for the Baseline Scenario with Moderate Growth

(Net generating capability, Gigawatts)

New England	1976	1985	1995	1985-1995
Coal	0.58	1.34	3.97	2.63
Oil & Gas	11.9	13.2	13.1	-0.10
Comb Cycle	0.08	0.31	0.31	0.0
Hydro	2.53	2.53	2.53	0.0
Turbine	1.52	2.28	2.28	0.0
Geothermal	0.0	0.0	0.0	0.0
Nuclear	4.14	9.87	20.0	10.13
TOTAL	20.8	29.5	42.2	12.7

Mid Atlantic	1976	1985	1995	1985-1995
Coal	20.3	24.5	38.2	13.7
Oil & Gas	24.5	25.0	24.1	-0.9
Comb Cycle	0.13	0.13	0.13	0.0
Hydro	6.69	8.05	8.05	0.0
Turbine	10.6	13.1	13.1	0.0
Geothermal	0.0	0.0	0.0	0.0
Nuclear	7.38	21.5	51.6	30.1
TOTAL	69.6	92.3	135	42.9

South Atlantic	1976	1985	1995	1985-1995
Coal	41.2	53.8	80.6	26.8
Oil & Gas	22.4	24.1	23.6	-0.5
Comb Cycle	0.0	1.40	1.40	0.0
Hydro	5.74	9.72	9.78	0.06
Turbine	9.10	15.1	15.5	0.4
Geothermal	0.0	0.0	0.0	0.0
Nuclear	9.67	27.5	72.0	44.5
TOTAL	88.1	132	203	71.3

Table 2-5 (cont.)

Projected Capacity Mix, by Region, for the Baseline Scenario with Moderate Growth

(Net generating capability, Gigawatts)

East North Central	1976	1985	1995	1985–1995
Coal	69.1	89.5	104.3	14.80
Oil & Gas	7.28	8.62	8.59	-0.03
Comb Cycle	0.0	0.0	0.0	0.0
Hydro	3.13	3.17	3.17	0.0
Turbine	6.80	11.7	12.0	0.30
Geothermal	0.0	0.0	0.0	0.0
Nuclear	8.69	28.8	79.3	50.5
TOTAL	95.0	142	207	65.6

East South Central	1976	1985	1995	1985–1995
Coal	30.5	37.0	44.6	7.60
Oil & Gas	4.32	4.63	4.33	-0.30
Comb Cycle	0.0	0.0	0.0	0.0
Hydro	5.98	7.53	7.53	0.0
Turbine	2.69	3.06	3.13	0.07
Geothermal	0.0	0.0	0.0	0.0
Nuclear	2.30	18.0	39.0	21.0
TOTAL	45.8	70.2	98.6	28.4

West North Central	1976	1985	1995	1985–1995
Coal	18.5	31.7	42.7	11.0
Oil & Gas	4.96	2.77	2.74	-0.03
Comb Cycle	0.0	0.09	0.09	0.0
Hydro	3.00	4.00	4.00	0.0
Turbine	4.81	7.88	8.50	0.62
Geothermal	0.0	0.0	0.0	0.0
Nuclear	4.00	6.28	14.0	7.72
TOTAL	35.3	52.7	72.0	19.3

Table 2-5 (cont.)

Projected Capacity Mix, by Region, for the Baseline Scenario with Moderate Growth

(Net generating capability, Gigawatts)

West South Central	1976	1985	1995	1985-1995
Coal	2.78	19.6	58.4	38.8
Oil & Gas	57.1	57.0	25.6	-31.4
Comb Cycle	0.23	0.46	0.46	0.0
Hydro	2.32	2.57	2.57	0.0
Turbine	2.78	5.83	12.4	6.57
Geothermal	0.0	0.0	0.0	0.0
Nuclear	0.90	9.03	34.0	25.0
TOTAL	66.1	94.5	133	38.9

N. Mountain	1976	1985	1995	1985-1995
Coal	1.27	3.03	5.27	2.24
Oil & Gas	0.07	0.07	0.07	0.0
Comb Cycle	0.0	0.0	0.0	0.0
Hydro	3.15	3.89	3.93	0.04
Turbine	0.08	0.60	0.61	0.01
Geothermal	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	0.0	0.0
TOTAL	4.57	7.59	9.88	2.29

S. Mountain	1976	1985	1995	1985-1995
Coal	12.8	19.5	27.1	7.6
Oil & Gas	3.50	3.26	2.18	-1.08
Comb Cycle	0.23	0.51	0.51	0.0
Hydro	3.14	3.67	3.67	0.0
Tub Turbine	1.75	2.73	2.83	0.10
Geothermal	0.0	0.0	0.0	0.0
Nuclear	0.0	0.67	7.73	7.06
TOTAL	21.4	30.3	44.0	13.7

Table 2-5 (cont.)

Projected Capacity Mix, by Region, for the Baseline Scenario with Moderate Growth

(Net generating capability, Gigawatts)

Pacific	1976	1985	1995	1985-1995
Coal	1.37	4.51	12.3	7.8
Oil & Gas	21.4	20.7	20.5	-0.2
Comb Cycle	0.57	5.08	5.08	0.0
Hydro	31.7	41.0	42.6	1.6
Turbine	1.77	6.56	7.66	1.1
Geothermal	0.32	1.72	1.93	0.21
Nuclear	3.39	16.2	47.0	30.8
TOTAL	60.5	95.8	137	41.3

Table 2-6.

Projected Coal-Fired Capacity by Regulatory Category

(Net generating capability, Gigawatts)

Moderate Growth Scenarios

Year	SIP Units	NSPS Units	Revised NSPS Units	Total
1980	206.8 (87.4%)	29.8 (12.6%)	0.0 (0%)	237
1985	212.5 (74.7%	39.3 (13.8%)	32.7 (11.5%)	285
1990	212.1 (59.7%)	39.3 (11.1%)	103.9 (29.2%)	355
1995	212.1 (50.8%)	39.3 (9.4%)	166.0 (39.8%)	417
2000	212.1 (43.5%)	39.3 (8.1%)	236.4 (48.5%)	488

High Growth Scenarios

Year	SIP Units	NSPS Units	Revised NSPS Units	Total
1980	206.9 (87.4%)	29.8 (12.6%)	0.0 (0%)	237
1985	212.6 (74.7%)	39.3 (13.8%)	32.7 (11.5%)	285
1990	212.3 (50.3%)	39.3 (9.3%)	170.8 (40.4%)	422
1995	212.3 (35.3%)	39.3 (6.5%)	349.7 (58.2%)	601
2000	212.3 (25.8%)	39.3 (4.8%)	570.1 (69.4%)	822

Table 2-7 gives projections of flue gas desulfurization ("scrubber") capacities for all the SO_2 control variants, assuming the revised particulate limit of 12.9 ng/J (0.03 lb/10^6 Btu). The numbers listed under "Capacity of FGD Systems" are measures of the size of the scrubbers, not of the units being scrubbed. These two capacities can differ, because the pollution control module allows for partial scrubbing of the flue gas. More specifically, we assume full scrubbing only when the required SO_2 removal equals or exceeds 90 percent. Less than 90 percent removal is achieved by scrubbing less than 100 percent of the gas at 90 percent removal efficiency. The "capacity" of the FGD system for an individual boiler is therefore the generating unit's name-plate capacity, times the fraction of the gas scrubbed (a number between 0.3 and 1.0).* This is a measure of the design size of the scrubber module. Finally, note that the figures reported under "Generating Capability" include all pollution control related capacity penalties: this explains why the FGD capacities exceed the "Revised NSPS" net generating capabilities for units subject to the 90 percent removal requirement.

The variations in the required FGD capacities for SIP and NSPS units in 1985 are due to differences among the scenarios in the sulfur levels of coals assigned to SIP and NSPS units. The sulfur content and region of origin of coals used in all the scenarios were derived from the output of a coal supply model developed by ICF, Inc.[5]

Table 2-8 shows a regional breakdown of installed FGD capacity in 1990 under the high growth scenario with the 90 percent removal requirement (H1.2(90)0.03).

Salient features of these results are:

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* Assumed coal sulfur values were adjusted downward to the compliance level whenever less than 30 percent SO_2 removal was required to comply with the applicable limit. This precludes the building of unrealistically small scrubbers.

Table 2-7

Projected Coal Capacity Using Flue Gas Desulfurization

(Gigawatts)

Scenario	Year	Unit Category	Generating Capability	Capacity of FGD Systems[a]
M1.2(0)0.1	1985	SIP and NSPS	285	52.5
		All	285	52.5
	1990	SIP and NSPS	355	61.3
		All	355	61.3
	1995	SIP and NSPS	417	67.1
		All	417	67.1
	2000	SIP and NSPS	487	75.1
		All	487	75.1
M1.2(90)0.03[b] (M1.2(90)0.1)	1985	SIP and NSPS	252	38.7
		Revised NSPS	31.2	35.5
		All	283	74.2
	1990	SIP and NSPS	252	38.7
		Revised NSPS	94.8	106
		All	347	145
	1995	SIP and NSPS	252	38.7
		Revised NSPS	151	168
		All	403	207
	2000	SIP and NSPS	252	38.7
		Revised NSPS	212	236
		All	464	275
H1.2(0)0.1	1985	SIP and NSPS	285	45.6
		All	285	45.6
	1990	SIP and NSPS	422	59.4
		All	422	59.4
	1995	SIP and NSPS	602	76.5
		All	602	76.5
	2000	SIP and NSPS	822	99.7
		All	822	99.7

a See text, page 2-13.

b Differences in these results for the two different particulate scenarios are insignificant.

Table 2-7 (continued)

Projected Coal Capacity Using Flue Gas Desulfurization

(Gigawatts)

Scenario	Year	Unit Category	Generating Capacity	Capacity of FGD Systems[a]
H1.2(90)0.03[b] (H1.2(90)0.1)	1985	SIP and NSPS	253	31.0
		Revised NSPS	39.2	34.0
		All	292	65.0
	1990	SIP and NSPS	253	31.0
		Revised NSPS	167	185.0
		All	420	216.0
	1995	SIP and NSPS	253	31.0
		Revised NSPS	336	372.0
		All	589	403.0
	2000	SIP and NSPS	253	31.0
		Revised NSPS	543	602.0
		All	796	633.0
M1.2(80)0.03	1985	SIP and NSPS	252	38.7
		Revised NSPS	40.3	31.6
		All	292	70.3
	1990	SIP and NSPS	252	38.7
		Revised NSPS	94.7	93.3
		All	347	132
	1995	SIP and NSPS	252	38.7
		Revised NSPS	151	149
		All	403	188
	2000	SIP and NSPS	252	38.7
		Revised NSPS	212	209
		All	464	248

a See text, page 2-13.

b Differences in these results for the two different particulate scenarios are insignificant.

Table 2-7 (continued)

Projected Coal Capacity Using Flue Gas Desulfurization

(Gigawatts)

Scenario	Year	Unit Category	Generating Capacity	Capacity of FGD Systems[a]
H1.2(80)0.03[b]	1985	SIP and NSPS	253	30.0
		Revised NSPS	40.5	30.1
		All	292	61.0
	1990	SIP and NSPS	253	30.0
		Revised NSPS	167	161.
		All	420	191
	1995	SIP and NSPS	253	30.0
		Revised NSPS	336	321
		All	589	351
	2000	SIP and NSPS	253	30.0
		Revised NSPS	543	527
		All	796	557
MO.5(0)0.03	1985	SIP and NSPS	252	39.7
		Revised NSPS	40.5	31.6
		All	292	71.3
	1990	SIP and NSPS	252	38.7
		Revised NSPS	95.9	93.5
		All	348	132
	1995	SIP and NSPS	252	38.7
		Revised NSPS	152	149
		All	404	188
	2000	SIP and NSPS	252	38.7
		Revised NSPS	212	208
		All	464	247

a See text, page 2-13.

b Differences in these results for the two different particulate scenarios are insignificant.

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Table 2-8

Regional Breakdown of Installed FGD Capacity in 1995, Scenario H1.2(90)0.03

(Gigawatts)

Region[a]	Net Coal-Fired Capacity	FGD Capacity
NE	6.75	6.52
MA	59.2	42.5
SA	102	75.5
ENC	158	81.5
ESC	54.4	23.2
WNC	50.6	31.5
WSC	87.5	84.1
NM	13.9	13.9
SM	32.4	24.5
PA	25.2	20.1
Nation	589	403

[a] See Table 2-1.

- Given the coal assignments used in this analysis and the present SO_2 emission limitations, installed FGD capacity would amount to 16 to 18 percent of net coal-fired generating capacity by 1985, remaining at approximately that level for the following decade.

- Under the "high growth" scenario, the 80 percent removal requirement increases installed FGD capacity from 59 Gw under the current standard to 191 Gw by 1990, and from 77 Gw to 351 Gw by 1995.

- Increasing the removal requirement from 80 to 90 percent further increases the installed FGD capacity by 10 to 15 percent by 1995, depending upon the post-1983 growth rate.

- The amount of FGD installed in response to a revised NSPS standard of 215 ng/J (0.5 lb/10^6 Btu) is nearly the same as that projected under the 80 percent removal scenario.

- The regions of the country with the highest installed scrubber capacities by 1995, assuming a 90 percent removal requirement, are West South Central (84 Gw), East North Central (82 Gw), and South Atlantic (76 Gw). These three regions contain 60 percent of the total installed scrubbing capacity in that year.

As indicated on the previous tables, our projections of capacity mix and scrubber usage (and, as we show in the next chapter, SO_2 emissions), are not sensitive to a revision of the current new source standard for particulates. This is because the coal assignments, capacity penalties, future-mix fractions and dispatch orders remain the same. The costs of control do increase – but not enough to affect these key determinants of industry behavior. The small size of the cost increase is due partially to the assumption, stipulated by EPA, that units burning low sulfur western coals would use fabric filters rather than precipitators to comply with new source standards. Given the control costs models used in this study,[6] universal use of precipitators would increase the costs of meeting the revised particulate standard.

Projections of utility coal consumption are shown in Figure 2-1 for the moderate and the high growth scenarios. (Variations in coal consumption due to the different SO_2 control assumptions are too small to be significant.) The curve starts in 1976 at 404 million metric tons (445 tons), which is very close to the actual utility "burn" in that year as reported by the Federal Power Commission,[7] 406 million metric tons (448 million tons).* In the year 2000 differences in electric demand growth rates after 1985 (3.4 to 5.5 percent) and in the percentage of coal-fired capacity added lead to a dramatic difference in coal consumption, 910 metric tons and 1,670 metric tons in the moderate and high demand growth cases, respectively.

The simulation model accounts for differences between coal mined and coal burned due to tonnage loss in coal preparation plants. (Changes in utility stockpiles are not considered.) For the sulfur levels of the coals assigned and our assumptions about the minimum sulfur levels which are available in uncleaned coals, the model projects that 32 million metric tons of coal would have had to be mined in 1976 to account for refuse from producing 114 million metric tons (126 million tons) of cleaned coal, assuming dense media separation processes with 80 percent weight recovery. This compares with the U.S. Bureau of Mines' estimate of 79 million metric tons (87 million tons) of steam and metallurgical coals that were cleaned by dense media separation processes in 1975.[8]

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* The FPC reports both deliveries and consumption. These may differ in any given year due to changes in stockpile levels.

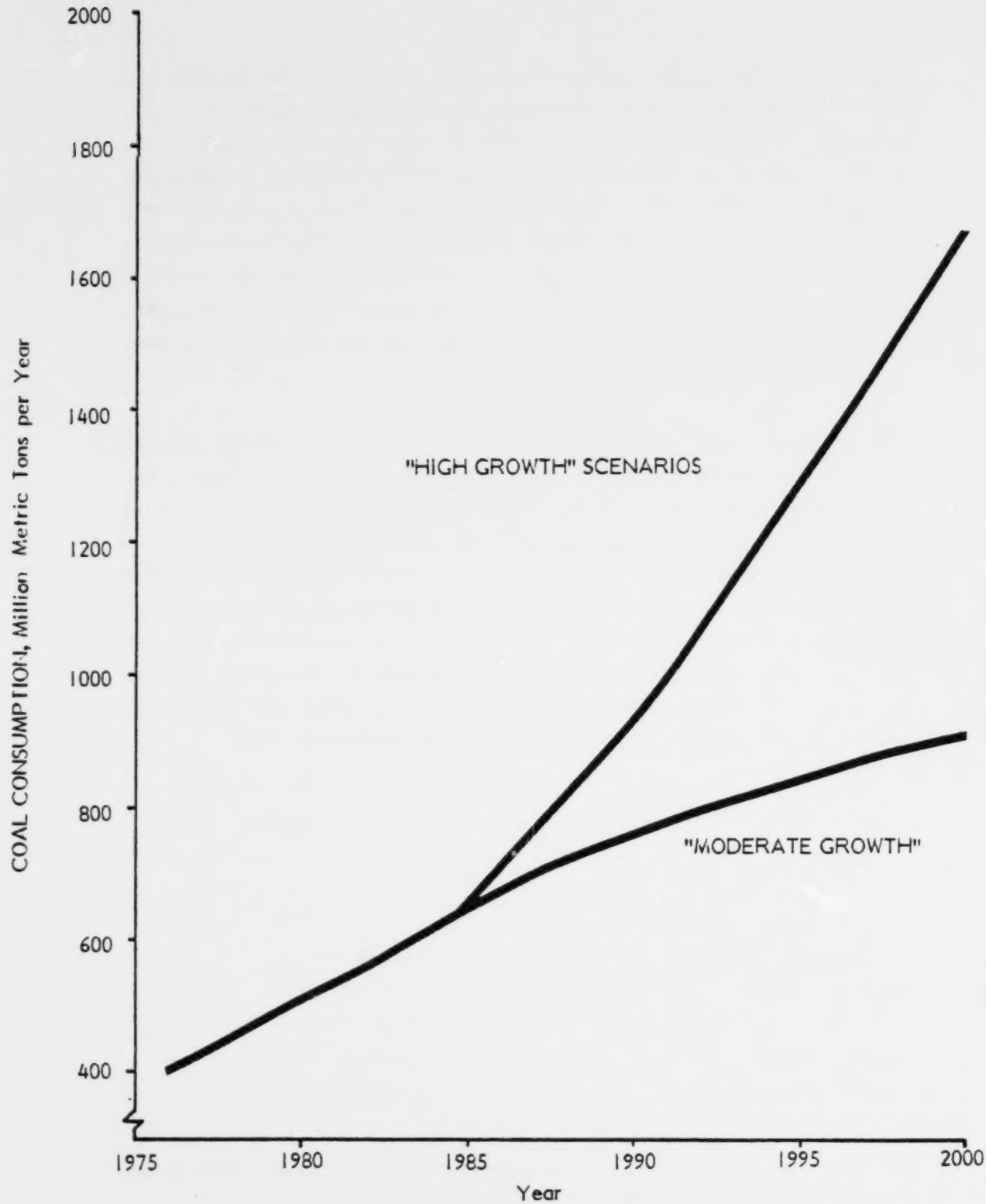

Figure 2-1. Projections of electric utility coal consumption.

3.0 AIR EMISSIONS, SOLID WASTES, WATER AND ENERGY

Emissions of the "criteria pollutants," SO_2, NO_x and particulates, from all fossil-fueled generating units under each of the scenarios are summarized in this section, using the geographic regions defined in Chapter 2. The implications of these emissions for ambient air quality will be discussed in Volume III.

Solid wastes considered are the sludges resulting from the use of FGD ("scrubber") systems. Following EPA's directives, there were three generic FGD systems considered: lime and limestone nonregenerable, and magnesium-oxide regenerable. The choice among these types for an individual generating unit was made on a random basis with the distribution of selections having the following probabilities:

Probability that a unit installing FGD will choose:

Region	Lime	Limestone	Mag-Ox
New England*	0	0	100%
All others	38%	57%	5%

The residuals module of the simulation model also calculates the water evaporated by cooling systems, water used by coal cleaning facilities, and the make-up water demanded by FGD systems. (FGD make-up replaces water lost by evaporation as well as that contained in the settled sludge.) Water data reported in this chapter will emphasize the FGD makeup component.

Like other pollution control devices, the use of FGD on a generating unit consumes energy and reduces the net generating capability of the unit. The energy requirement ranges from three to ten percent of the boiler input, depending upon the kind of system used, the coal characteristics, and the level of

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* See Table 2-1.

control. Generating capability penalties average about five percent of the uncontrolled value, again depending upon the particular system and the operating conditions. Parameters relating to energy and capability penalties, as well as the costs of FGD and particulate controls, were adjusted for this study to be consistent with those developed for EPA by Pedco Environmental, Inc., another contractor supporting the NSPS review effort.[6]

3.1 BASELINE EMISSIONS OF SO_2, NO_x, AND PARTICULATES

National emissions of SO_2, NO_x, and particulates from fossil-fueled electric generating units in 1976, the first year simulated, are shown in Table 3–1. Also shown are some estimates of emissions from other references.

In comparing the results of these simulations in the years before 1983 with data from other sources, it is important to keep in mind the assumptions we have used regarding compliance with emission regulations. It was noted in Table 1–1 that full compliance with State Implementation Plan (SIP) limits is not achieved in the model until 1980. In particular, retrofitting of high efficiency electrostatic precipitators* and FGD systems for purposes of compliance with SIP limits occurs over the period 1977 through 1979. This compliance schedule causes the particulate levels shown in Table 3-1 to decrease dramatically between 1976 and 1980, even though the amount of electrical energy generated from coal and oil steam plants increases by approximately 23 percent over that period. Units that comply with their SIP limit by use of low sulfur coal, rather than by retrofit of FGD, are in compliance as of the first year of the simulation. Since only a

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* Particulate controls of varying degree were imposed upon most coal-fired generating plants even before passage of the original Clean Air Act Amendments in 1970. Because of this, we assume that cyclone devices were used by all units on-line by the base year for the simulation (1975). Collection efficiencies are assumed to be 50 percent (mass basis) for units on-line before 1950, and 85 percent for newer units. "Uncontrolled" emissions of particulates include these assumptions.

Table 3-1

National Power-Plant Emissions of SO_2, NO_x, and Particulates in 1976 and 1980
(Million Metric Tons)

Pollutant	Calculated Emissions in 1976	Calculated Emissions in 1980	1973 Emissions from Source 1[b]	1975 Emissions from Source 2[c]
SO_2	13.6	14.4	17.6	12.1
NO_x	4.6	5.6	6.3	6.1
Particulates	4.9	0.8	3.3	2.4

[a] One ton (2000 lb) = 0.9070 metric ton.

[b] U.S. Environmental Protection Agency, 1973 National Emissions Report 450/2-76-007, 1976.

[c] U.S. Energy Research and Development Administration, Regional Air Emissions Analysis of Alternative Energy Policies in 1985, 1977 (EPA data).

relatively small fraction of SIP-controlled coal-fired units will use FGD (about 23 percent) and since oil-fired units in the model comply with all SO_2 emission limits through use of low sulfur oil, the effect of the 1980 deadline for compliance is less important in comparing the SO_2 numbers. The observed rise in SO_2 is due to the increase in fossil-fired generation between 1976 and 1980. Finally, very few states have SIP limits for NO_x, so the assumed compliance period is not a factor in comparing the NO_x values with other estimates. As can be seen the other estimates indicated compare well with the Utility Simulation Model results.

Projections over time of aggregate emissions for the three criteria pollutions are shown in Figures 3-1, 3-2, and 3-3, assuming no change in the current NSPS. These curves define the "baseline" projections against which reductions in emissions due to imposition of different revised standards can be weighed. The

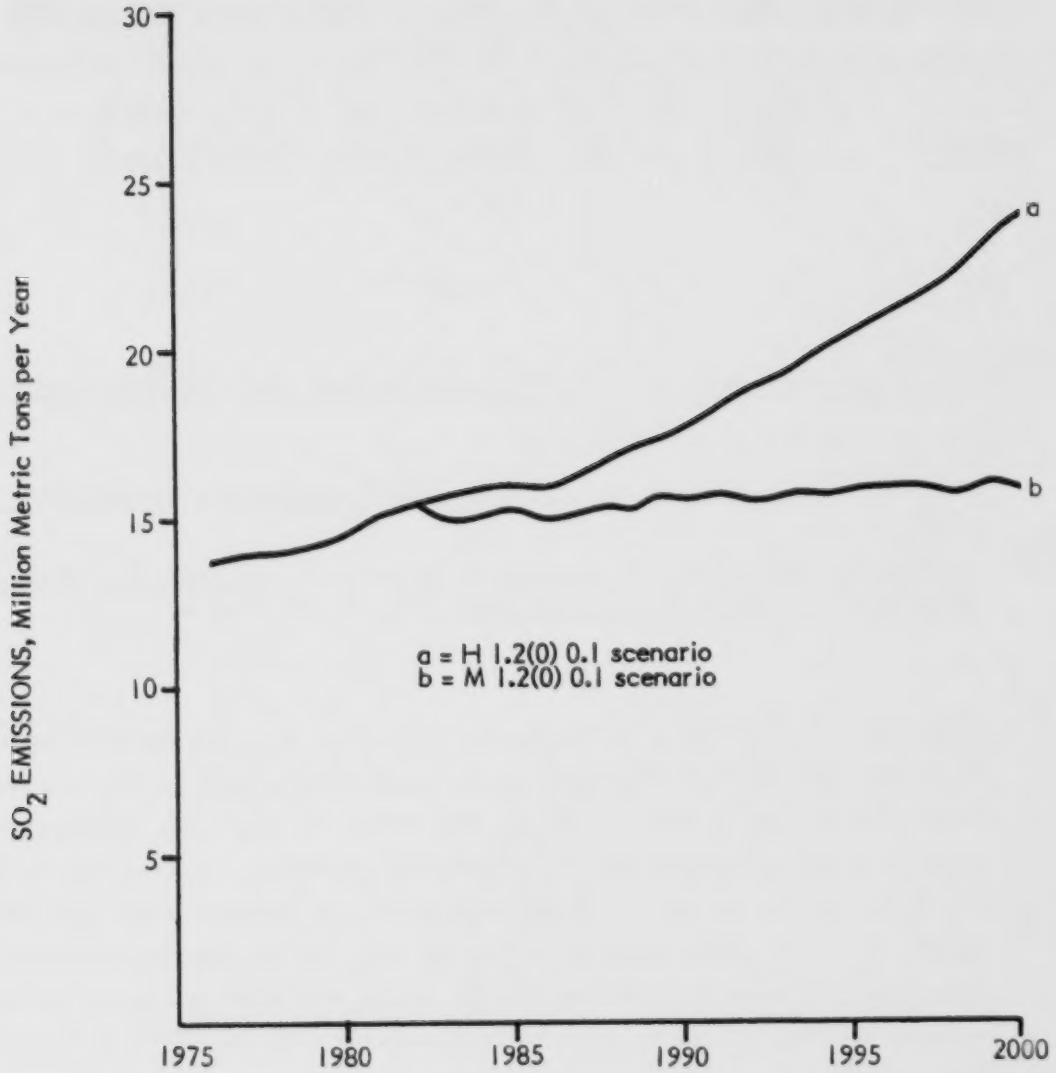

Figure 3-1. National power-plant SO_2 emissions under the baseline scenarios.

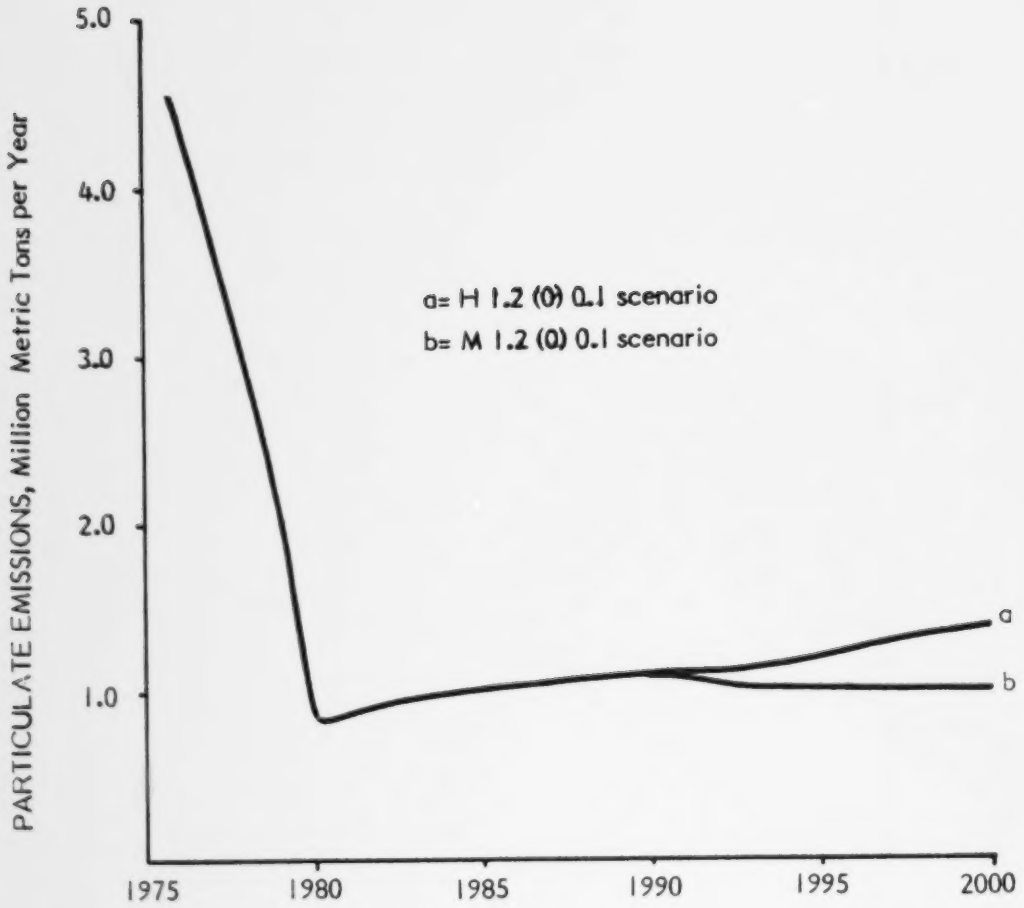

Figure 3-2. National power-plant particulate emissions under baseline scenarios.

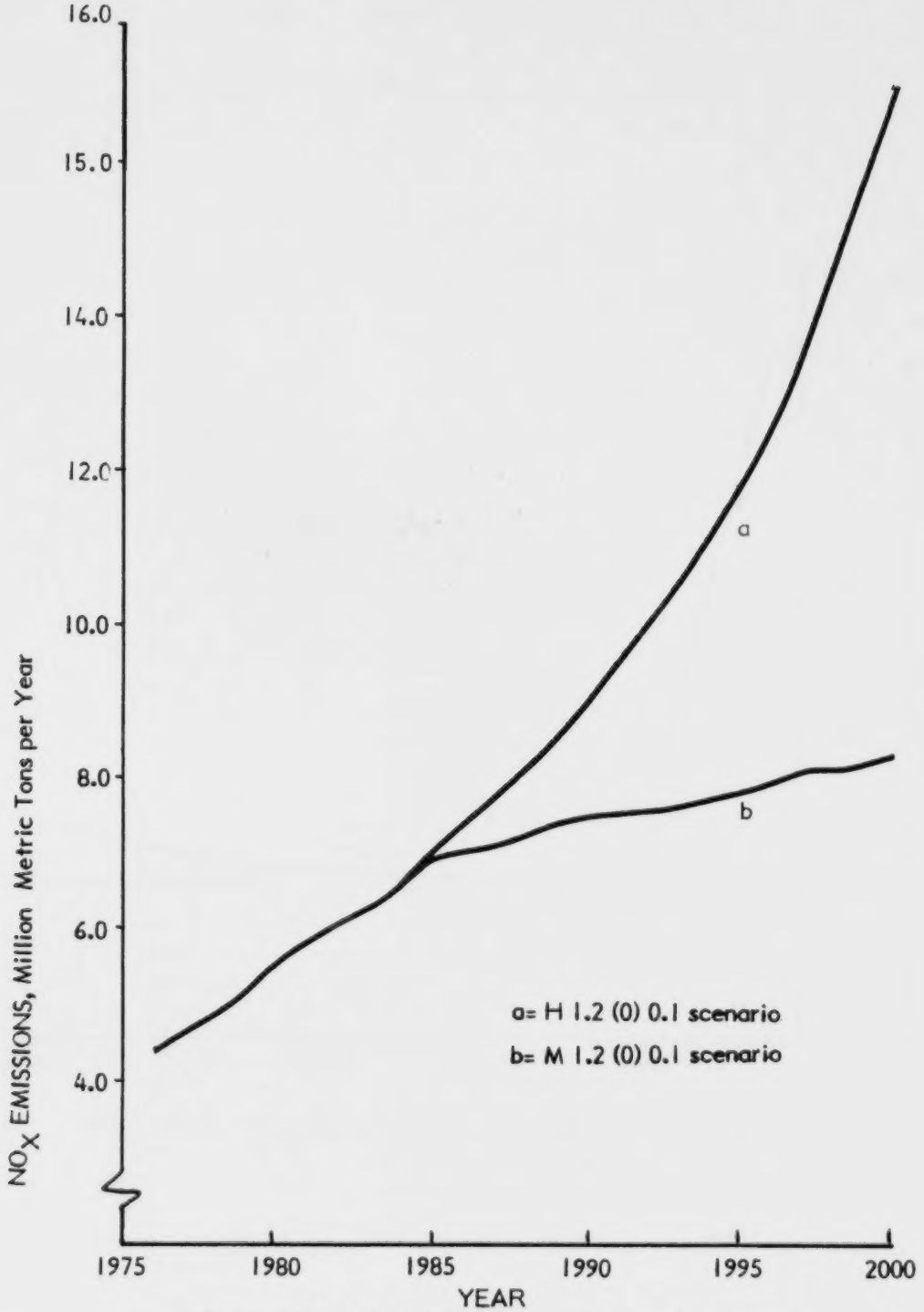

Figure 3-3. National power-plant NO_X emissions under the baseline scenarios.

results lead to the following conclusions about aggregate emissions from electric power generation:

- National emissions of SO_2 from electric power plants will increase from 1976 partial compliance levels (about 13.6 million metric tons) at about 2 percent per year until 1985, if electricity demand grows at 5.8 percent per year until 1985.

- Under high demand growth after 1985 (5.5 percent per year in total demand and roughly 6 percent per year in coal-fired generation) national SO_2 emisisons under current standards will increase at approximately 2.5 percent per year. A revised NSPS with 90 percent required removal will slow this growth in national SO_2 emissions to less than one percent per year between 1985 and 2000.

- Under moderate demand growth and the present emission standards national SO_2 emissions will increase at approximately 0.4% per year from 1985 to 2000. A revised NSPS with 90 percent removal will bring about a net decrease in national SO_2 emissions after 1985. By the year 2000 national SO_2 emissions will be approximately equal to or below 1976 aggregate SO_2 emissions.

- In 1995 SO_2 emissions in the high demand case will be reduced from the baseline projections (current NSPS) by 17 percent for mandatory 80 percent post-combustion removal and by 27 percent for mandatory 90 percent post-combustion removal. In 2000 the reduction of national SO_2 emissions is projected to be 35 percent with the 90 percent removal standard, 21 percent with the 80 percent removal standard.

- A reduction in the electricity demand growth rate after 1985 to 3.4 percent per year, along with a continuation of the current NSPS SO_2 standard, will result in a national SO_2 emissions level in 2000 comparable to the level of emissions achievable under a 5.5 percent per year demand growth rate after 1985 and the 90 percent SO_2 removal standard. There are, however, regional differences in the distribution of emissions in these cases.

- Assuming the moderate growth rate, total particulate emissions will increase only slightly above the present full compliance level, and will remain nearly constant there-

after, again assuming full compliance with existing emission limitations. High demand growth by the mid-1980s would lead to further growth in particulate emissions throughout the 1990s to about 1.1 million metric tons per year.

- Emissions of NO_x from power generation will increase substantially under current standards, even assuming an effective electricity demand conservation program. Extensive deployment of new combustion technologies (such as fluidized bed), would be needed in order to slow the rise in nationwide NO_x emissions in the 1990s.

In 1976 the national average capacity factor* simulated for all coal-fired generating units was 0.54. Because of increasing demand the simulated capacity factor rises to 0.59 in 1985. This increase is reasonable because of falling utility reserve margins in the early 1980s and the emphasis on coal-fired generation. Since existing coal units are generally cheaper than newer units to operate and since existing coal units are subject to SIP emission limits which are usually less stringent than the current new source limits of 516 ng/J (1.2 lb/10^6 Btu) for coal and 413 ng/J (0.8 lb/10^6 Btu) for oil units, this increase in capacity factors for existing units will have adverse air quality impacts. Indeed plants subject to SIP regulation account for the bulk of SO_2 emissions as shown in Table 3–2. This data suggests that tighter standards for SIP plants may eventually be needed to substantially reduce SO_2 emissions in some regions.

In the Utility Simulation Model each type of generating unit is constrained by an availability and a maximum capacity factor for each state. This reflects the fact that all units need to be out of commission for scheduled maintenance and unanticipated down-time. The projections reported here assume a yearly

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* The capacity factor measures the extent to which a generating unit is utilized. It is calculated as the ratio of the energy actually generated in a given year to that which would have been generated if the unit had run at full rated capability throughout the entire year. "Base-load" units normally have capacity factors between 0.5 and 0.8.

Table 3-2

Aggregate SO_2 Emissions from Fossil-Fueled Generation, by Category of Unit

(10^6 metric tons/year)

	Scenario M1.2(0)0.1[a]			Scenario H1.2(0)0.1[b]		
Year	SIP Units	NSPS Units	Post 1982[c] Units	SIP Units	NSPS Units	Post 1982[c] Units
1985	13.3 (89%)	1.1 (7%)	0.7 (4%)	14.1 (89%)	1.0 (7%)	0.6 (4%)
1995	11.5 (73%)	1.0 (6%)	3.3 (21%)	12.3 (61%)	1.1 (5%)	6.9 (34%)
2000	10.5 (66%)	1.0 (7%)	4.4 (27%)	11.7 (49%)	1.1 (5%)	11.0 (46%)

a Moderate growth baseline. (Chapter 1, Table 1-4)

b High growth baseline.

c These are assumed to be subject to any revision to the current NSPS.

NOTE: See Table 2-6 for corresponding generating capacities.

availability of 0.85 for coal units and base-loaded coal units may be dispatched up to a maximum capacity factor of 0.77. Daily load curves and a least-cost dispatch order always lead to lower aggregate capacity factors for each class of unit for each state and year. However, it has been argued that future availabilities of coal units with FGD systems will be less than present availabilities. The question of availabilities and of the expected capacity factors is of importance, particularly in the early 1980s when a number of states will have reduced reserve margins. Further work is anticipated to test the sensitivity of the absolute levels of emissions to our assumptions of future availabilities and maximum allowable capacity factors.

3.2 EMISSION CHANGES DUE TO NSPS REVISIONS

3.2.1 Some Comments on the Alternatives

As detailed in Chapter 1, there are three alternative forms of a revised New Source Performance Standard for SO_2 emissions from coal-fired boilers which are discussed in this report:

- Mandatory 90 percent post-combustion SO_2 removal with an upper limit on emissions of 516 ng/J (1.2 lb/10^6 Btu).
- Mandatory 80 percent post-combustion SO_2 removal with the same upper limit.
- An upper limit of 215 ng/J (0.5 lb/10^6 Btu) with no postulated minimum percentage removal.

Depending upon the circumstance, either the percentage removal requirement or the emission "cap" can be the controlling factor. Consider an "average" midwestern coal with a sulfur content of 3.5 percent and a heating value of 25,600 kJ/kg (11,000 Btu/lb). The rate of uncontrolled SO_2 emissions in this case would be 2,580 ng/J (6.0 lb/10^6 Btu).* Emissions under the 90 percent removal requirement would be 258 ng/J (0.6 lb/10^6 Btu), and 516 ng/J (1.2 lb/10^6 Btu) with the 80 percent variation. In both cases, the 516 ng/J cap is not controlling -- and in fact it would not be controlling for all coals whose sulfur content is equal to or less than about 1,370 nanogram sulfur per Joule (3.2 lb/10^6 btu), which are the bulk of the utility steam coals currently being burned. Note also that for the example coal just considered, 80 percent removal would be dictated by the current NSPS of 516 ng/J. Hence, utilities subject to the current NSPS and

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* We assume an emission factor, K, of 0.95 for bituminous coals and 0.85 for subbituminous coals. Uncontrolled emissions of SO_2 are calculated as $(2KS(\%))/(HV/10^4)$, where HV is the coal heating value (English units).

burning coals where sulfur levels are at least 1,370 ng/J (3.2 lb sulfur/10^6 Btu) would incur no additional SO_2 control costs in complying with the 80 percent, 516 ng/J "cap" standard, assuming the averaging times used to define compliance and monitoring requirements were the same.

The third type of revised standard, a limit of 215 ng/J with no minimum removal requirement, would amount to a less stringent standard than the 90 percent removal case for many coals, namely those with sulfur levels less than 1,130 ng/J (2.63 lb/10^6 Btu). For a good quality bituminous coal with two percent sulfur and a heating value of 27,900 kJ/kg (12,000 Btu/lb), an emission limit of 215 ng/J (0.5 lb/10^6 Btu) and an 80 percent removal requirement are nearly equivalent, all other factors being equal.

Quantitative projections of SO_2 and particulate emissions by geographic region under the present standard and the candidate NSPS revisions are given in the next section. Projections of NO_x emissions are not shown, since all alternatives assumed the same limit (258 ng/J or 0.6 lb/10^6 Btu), and because the changes from the baseline projections are very small (less than 10 percent decrease in the year 2000). Variations in sulfur emissions brought about by a change in the particulate limit are also small, and therefore not all combinations of revised particulate and SO_2 limits are shown. Finally, the reader is reminded that we have assumed in this study that the NSPS revisions apply only to coal-fired generating units of 25 Mw or greater rated capacity which begin operation in 1983 or later. As a result, variations caused by revised controls are zero or negligible before 1985. (Refer to Chapter 2, Table 2–6 for a breakdown of generating capacity by SIP, NSPS, and revised NSPS categories.)

3.2.2 Emission Data

National and regional projections of SO_2 emissions under all the SO_2 control variants are given in Table 3–3, including the baseline scenarios. National emissions are plotted in Figures 3–4 and 3–5. (Results for scenario MO.5(0)0.03)

Table 3-3

Regional and National Power-Plant SO_2 Emissions

(Million metric tons per year)

Scenario M1.2(0)0.1

Region	1976	1985	1990	1995	2000
NE	.23	0.25	0.31	0.25	0.26
MA	2.06	1.70	1.66	1.62	1.69
SA	3.09	3.62	3.53	3.73	3.80
ENC	3.50	3.96	3.79	3.69	3.61
ESC	2.64	2.44	2.38	2.28	2.00
WNC	1.32	1.61	1.58	1.70	1.83
WSC	0.11	0.95	1.52	1.73	1.91
NM	0.12	0.09	0.13	0.18	0.24
SM	0.34	0.23	0.30	0.28	0.28
PA	0.20	0.31	0.31	0.33	0.29
National	13.6	15.2	15.5	15.8	15.9

Scenario M1.2(80)0.03

Region	1985	1990	1995	2000
NE	.24	0.29	0.22	0.22
MA	1.68	1.59	1.52	1.53
SA	3.93	3.82	3.82	3.68
ENC	4.36	3.96	3.64	3.22
ESC	2.44	2.39	2.28	2.05
WNC	1.43	1.37	1.53	1.76
WSC	0.78	1.02	1.12	1.14
NM	0.07	0.07	0.09	0.11
SM	0.20	0.20	0.20	0.18
PA	0.27	0.25	0.21	0.16
National	15.4	15.0	14.3	14.1

Table 3-3 (continued)

Regional and National Power-Plant SO_2 Emissions

(Million metric tons per year)

Scenario M1.2(90)0.03

Region	1985	1990	1995	2000
NE	0.23	0.25	0.18	0.18
MA	1.65	1.49	1.36	1.29
SA	3.88	3.60	3.49	3.24
ENC	4.30	3.90	3.58	3.17
ESC	2.44	2.35	2.25	2.00
WNC	1.43	1.35	1.49	1.69
WSC	0.74	0.84	0.79	0.76
NM	0.06	0.05	0.06	0.07
SM	0.19	0.17	0.16	0.13
PA	0.26	0.22	0.19	0.13
National	15.2	14.3	13.6	12.7

Scenario M0.5(0)0.03

Region	1985	1990	1995	2000
NE	0.23	0.26	0.19	0.18
MA	1.65	1.49	1.37	1.30
SA	3.88	3.61	3.50	3.26
ENC	4.30	3.90	3.59	3.17
ESC	2.44	2.36	2.25	2.01
WNC	1.43	1.41	1.53	1.75
WSC	0.79	1.08	1.20	1.23
NM	0.08	0.09	0.12	0.16
SM	0.21	0.23	0.25	0.25
PA	0.28	0.27	0.24	0.19
National	15.3	14.7	14.3	13.5

Table 3-3 (cont.)

Regional and National Power-Plant SO_2 Emissions

(Million metric tons per year)

Scenario H1.2(0)0.1 Region	1985	1990	1995	2000
NE	0.25	0.26	0.32	0.44
MA	1.67	1.62	1.72	1.87
SA	4.04	4.19	4.67	5.18
ENC	4.29	4.75	5.45	6.14
ESC	2.43	2.28	2.26	2.44
WNC	1.56	1.63	1.93	2.29
WSC	0.94	1.84	2.71	3.49
NM	0.07	0.14	0.28	0.42
SM	0.23	0.31	0.38	0.56
PA	0.32	0.43	0.60	0.90
National	15.9	17.5	20.3	23.8

Scenario H1.2(80)0.03 Region	1985	1990	1995	2000
NE	0.24	0.24	0.29	0.38
MA	0.00	1.67	1.97	2.16
SA	3.75	3.96	4.04	4.09
ENC	3.66	4.11	4.78	5.56
ESC	2.40	2.30	2.25	2.51
WNC	1.30	1.34	1.65	1.91
WSC	0.75	0.98	1.22	1.44
NM	0.06	0.09	0.12	0.15
SM	0.20	0.20	0.21	0.24
PA	0.26	0.26	0.26	0.32
National	14.3	15.2	16.8	18.8

Table 3-3 (cont.)

Regional and National Power-Plant SO_2 Emissions

(Million metric tons per year)

Scenario H1.2(90)0.03

Region	19	1985	1990	1995	2000
NE	1	0.23	0.20	0.22	0.24
MA	3	1.65	1.54	1.59	1.60
SA	6	3.70	3.62	3.46	3.27
ENC	4	3.60	3.91	4.29	4.67
ESC	3	2.39	2.27	2.37	2.47
WNC	1	1.30	1.31	1.59	1.75
WSC	2	0.73	0.82	0.90	0.98
NM	0	0.06	0.07	0.08	0.09
SM	0	0.19	0.17	0.15	0.15
PA	1	0.25	0.24	0.22	0.24
National	24	14.1	14.2	14.9	15.5

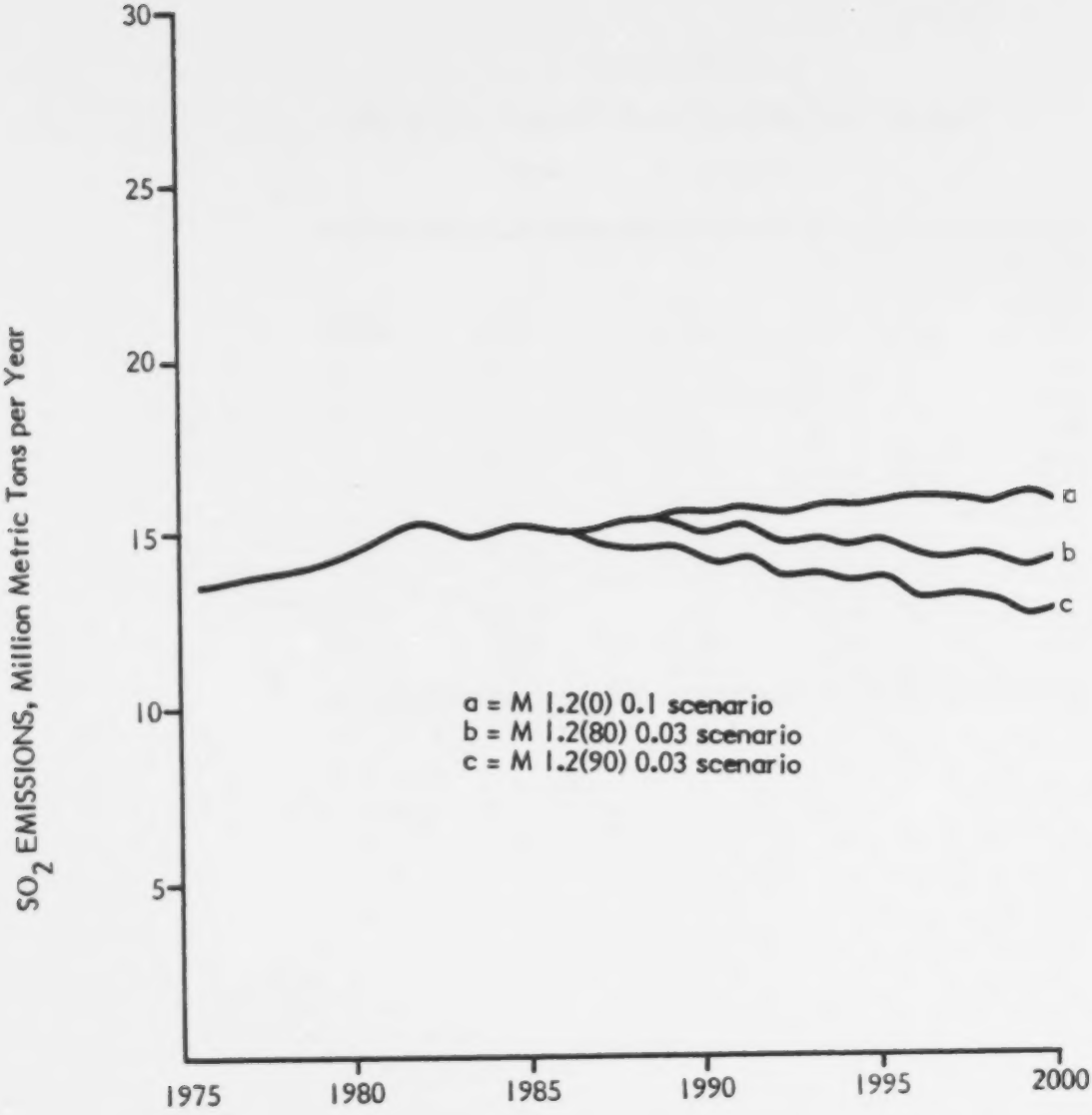

Figure 3-4. National power-plant SO_2 emissions under alternative control scenarios, moderate growth.

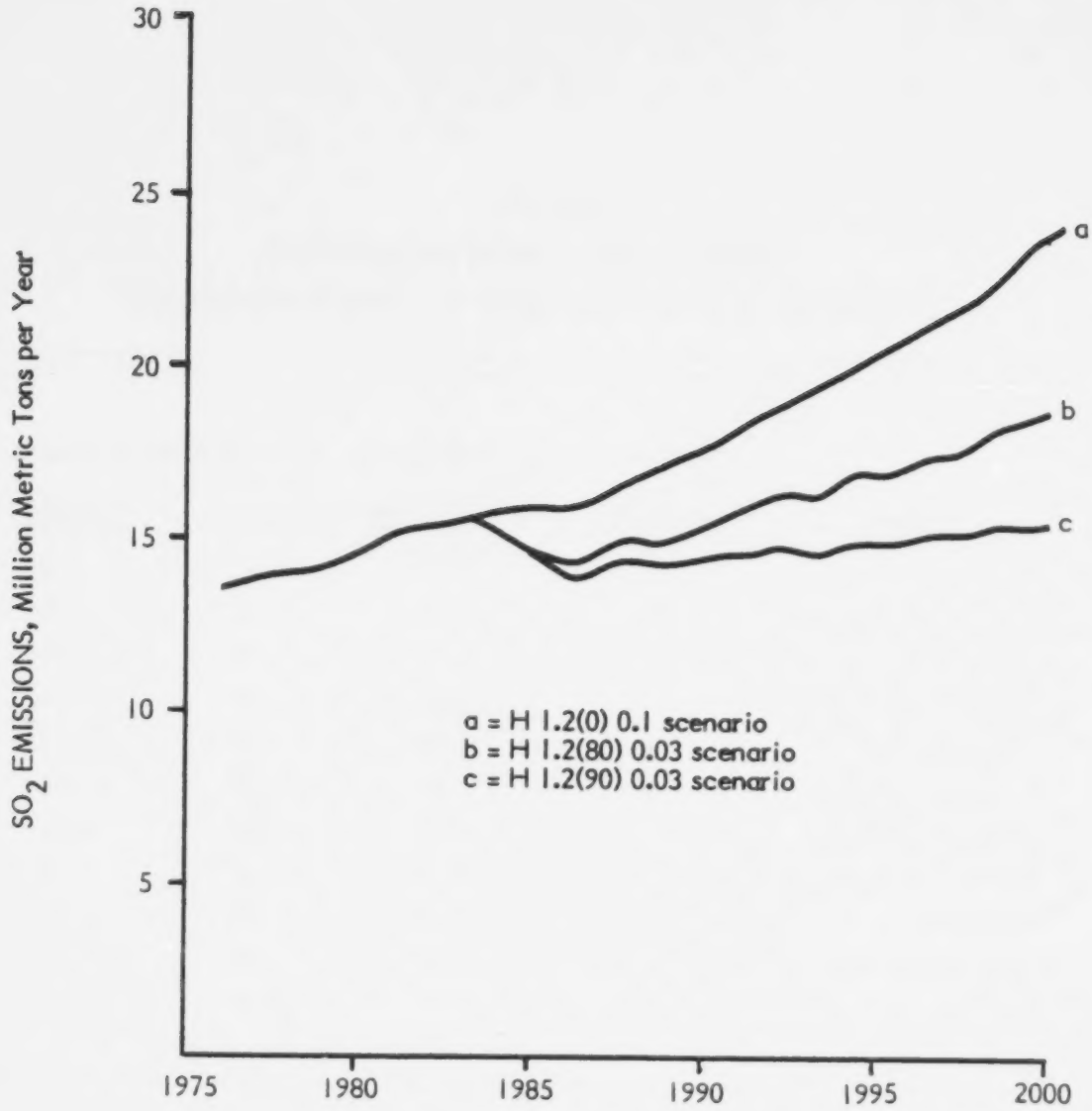

Figure 3-5. National power-plant SO_2 emissions under alternative control scenarios, high growth.

Table 3-4

Regional Emission Reductions in 1990 Due to Mandatory 90 Percent SO_2 Removal – High Growth Scenarios

Region	(Million metric tons emitted) H1.2(0)0.1	H1.2(90)0.03	Change in SO_2 Emissions 10^6 Tonnes	Percent
South Mountain	0.32	0.17	- .15	-47%
West South Central	1.85	0.82	-1.03	-56%
North Mountain	0.15	0.07	- .08	-53%
Pacific	0.43	0.25	- .18	-42%
New England	0.26	0.20	- .06	-23%
West North Central	1.64	1.31	- .33	-20%
East North Central	4.75	3.91	- .84	-18%
South Atlantic	4.20	3.63	- .57	-14%
Mid Atlantic	1.63	1.54	- .09	- 6%
East South Central	2.28	2.27	- .01	- 0%
National	17.5	14.2	-3.3	-19%

are not shown because the results are close to those for scenario M1.2(80)0.03: see Table 3–3.)

The revised standards have the greatest relative impact in those geographic areas which do not presently have a large base of coal-fired generation. This is particularly true of the West South Central region in which 87 percent of the base-year (1975) generating capacity was oil and gas-fired. For the 90 percent control scenario with high growth Table 3-4 shows aggregate emission reductions in 1990 by region.

In 1990 a ninety percent removal standard reduces national SO_2 emissions by 3.3 million metric tons (19%), while the West South Central region (56%), North Mountain region (53%), South Mountain region (47%), Pacific region (42%) and the New England region (23%) have the greatest percentage emissions reductions. In terms of total tonnage emission reduction the West South Central, East North Central and South Atlantic regions have the largest SO_2 emissions removal.

National projections of particulate and NO_x emissions, assuming the higher growth rate, are shown in Table 3–5 and Figure 3–6.

Table 3-5a

Regional and National Power-Plant NO_x Emissions

(Million metric tons per year)

Scenario HI.2(90)0.03

Region	1985	1990	1995	2000
NE	.11	.13	.17	.26
MA	.69	.80	1.10	1.34
SA	1.23	1.58	1.85	2.13
ENC	1.66	2.02	2.57	3.18
ESC	.62	.65	.81	1.03
WNC	.75	.91	1.32	1.78
WSC	1.08	1.81	2.61	3.61
NM	.19	.31	.47	.62
SM	.45	.56	.66	.82
PA	.33	.56	.73	1.17
National	7.17	9.33	12.29	15.93

Table 3-5b

Regional and National Power-Plant Particulate Emissions

(Million metric tons per year)

Scenario HI.2(0)0.1

Region	1985	1990	1995	2000
NE	.016	.018	.023	.034
MA	.14	.12	.11	.10
SA	.26	.28	.34	.39
ENC	.25	.27	.31	.36
ESC	.11	.11	.11	.12
WNC	.10	.12	.14	.15
WSC	.06	.08	.09	.11
NM	.005	.006	.009	.011
SM	.044	.045	.043	.042
PA	.033	.037	.040	.055
National	1.02	1.09	1.22	1.38

Scenario HI.2(90)0.03

Region	1985	1990	1995	2000
NE	.015	.012	.013	.015
MA	.14	.12	.11	.11
SA	.24	.23	.22	.21
ENC	.24	.25	.27	.28
ESC	.12	.12	.13	.14
WNC	.070	.096	.120	.137
WSC	.04	.06	.08	1.05
NM	.005	.007	.010	.012
SM	.042	.037	.031	.031
PA	.030	.035	.037	.048
National	.94	.97	1.03	1.08

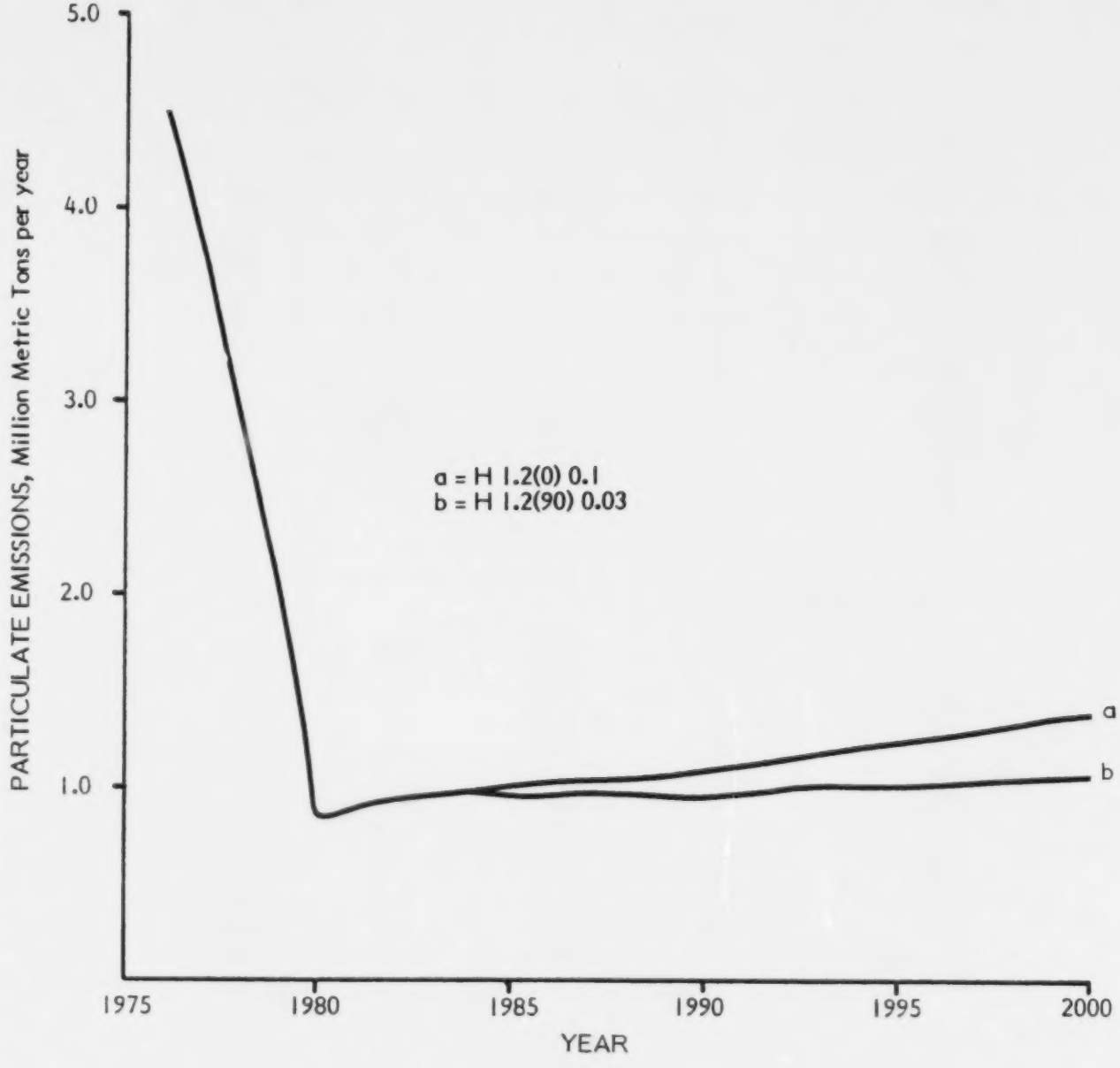

Figure 3-6. National power-plant particulate emissions, high growth

These results show that tightening the particulate NSPS for coal-fired units from the current 43 ng/J (0.1 lb/10^6 Btu) to 13 ng/J (0.03 lb/10^6 Btu) reduces total particulate emissions from power generation by 11 percent by 1990 and by 22 percent by 2000, assuming a 5.5 percent per year energy demand growth after 1985. (Corresponding results for the lower growth rate scenarios are 9.0 percent and 12 percent, respectively.) Changes in aggregate emissions of NO_x due to a revised NSPS value of 258 ng/J (0.6 lb/10^6 Btu) are negligible, since emissions from the large base of unaffected (pre 1983) units swamp the 14 percent reduction achieved by individual post 1982 units. (Similarly, it should be remembered that the revised particulate standard would reduce emissions from individual post-1982 units to one-third, which might have a more substantial effect at the local level than the national aggregate numbers imply.)

Salient features of these data can be summarized as follows:

- The maximum reduction in national SO_2 emissions from the level projected with the current NSPS is projected to be 35 percent, obtained in the year 2000 under high growth conditions with a 90 percent removal revised standard.

- Relaxing the SO_2 removal requirement from 90 percent to 80 percent reduces the maximum projected reduction to 21 percent.

- Assuming a moderate electricity demand growth rate after 1985, the maximum projected reduction in SO_2 emissions in 2000 at the national level is 20 percent.

- More stringent new source standards have a more substantial impact at the regional level: emissions of SO_2 in the Mountain and West Central states will be reduced by 49 percent and 39 percent by 1990, respectively, assuming the 90 percent removal requirement.

- Given the coal sulfur levels used in this analysis, the amount of SO_2 emitted under the 80 percent removal standard and the 215 ng/J (0.5 lb/10^6 Btu) standard are nearly the same in most regions. Nationally, emissions differ by a maximum of four percent. In the Mountain states, where relatively low sulfur coals are used, the 80 percent removal requirement further reduces emissions by about 30 percent in 2000.

- Revising the new source standard for particulates downward to 13 ng/J (0.03 lb/10^6 Btu) reduces national aggregate emissions by a maximum 11 percent in 1990 and 22 percent in 2000.

3.3 SOLID WASTES

Since this analysis assumes that lime and limestone FGD systems will be the predominate technology used to meet the revised SO_2 emissions standards, quantifying the solid wastes generated by them is an important part of the impact assessment.* The principal chemical constituents of FGD sludge are calcium sulfite ($CaSO_3$), calcium sulfate ($CaSO_4$), and calcium carbonate (limestone, $CaCO_3$). Sludge solids also contain various trace elements with concentrations ranging up to 100 mg/l. Some of these, such as soluble species of mercury, are considered toxic. (Arsenic, lead, and selenium are also of concern.) The potential environmental problems associated with sludge disposal, and the available techniques that may be used to solve these problems, are discussed in another report commissioned by EPA.[10]

Tons of sludge generated by FGD systems under the high growth scenarios are shown in Table 3–6. Note that the figures are expressed on a dry basis. The actual mass of sludge that has to be disposed is double the tonnage shown since the settled waste product is approximately 40-50 percent water. (Also, collected fly ash is not included in these figures.)

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* Our assumptions about the distribution of different types of FGD systems are given at the beginning of Chapter 3.

Table 3-6

Projections of Sludge Produced by FGD Systems

(Million metric tons, dry basis)

Region[a]	Year = 1990			Year = 1995		
	H1.2(0)0.1	H1.2(80)0.03	H1.2(90)0.03	H1.2(0)0.1	H1.2(80)0.03	H1.2(90)0.03
NE	negligible[b]	negligible[b]	negligible[b]	negligible[b]	negligible[b]	negligible[b]
MA	0.52	3.6	4.5	0.38	8.3	10.
SA	1.8	7.9	9.0	1.5	13.	15.
ENC	2.0	5.0	5.7	4.7	11.	13.
ESC	0.14	0.43	0.50	0.044	1.3	2.0
WNC	0.	0.48	0.59	0.	1.8	2.2
WSC	0.89	3.6	4.1	0.90	6.8	7.8
NM	0.18	0.67	0.77	0.18	1.1	1.3
SM	0.82	1.2	1.4	0.76	1.5	1.8
PA	0.18	0.64	0.88	3.7	1.1	1.4
Nation	8.1	24.	27.	12.	46.	55.

a See Table 2-1.

b See discussion at beginning of this chapter: wastes produced by regenerable systems are neglected.

Estimates of the land requirements for sludge ponding are shown in Table 3–7, assuming that the settled sludge is allowed to accumulate to a depth of 9.1 meters (30 feet), and that it is 47 percent water with a density of 1.4 g/cc.[10] The areas shown are cumulative for the period 1990 to 2000.

The solid waste besides scrubber sludge which is produced in quantity at a generating plant is coal ash. Approximately 80 percent of the ash is carried with the flue gas (fly ash), the remaining being bottom ash. All but a few percent of the fly ash must be captured to satisfy even the SIP emission limits (limits for particulates averaging about 86 ng/J, or 0.2 lb/10^6 Btu), and therefore essentially all of the coal ash appears as solid waste. Since the particulate limits considered here are in terms of emission rates (grams per Joule or pounds per million Btu) rather than percent removals, ash production depends mainly on the growth in coal consumption. Thus variations among the different SO_2 control options are not significant. Values for 1990, 1995, and 2000 are shown in Table 3–8. By dividing these figures by the total coal tonnages consumed in these years (cf. Figure 2–1) we infer an average coal ash content of about eight percent by weight.

Assuming an ash storage requirement of 1.54 cubic meters per metric ton of ash and a storage depth of nine meters,[10] cumulative ash production over the years 1990–2000 under the high growth assumption would require 176 square kilometers (68.0 mi^2) of storage area. This compares with the 91.5 square kilometers (35.3 mi^2) for sludge disposal shown in Table 3–7.

3.4 WATER REQUIREMENTS

Table 3-9 gives the regional breakdown of water consumed by FGD systems under the moderate and high growth scenarios, assuming full scrubbing of all post 1982 coal-fired units (90 percent SO_2 removal requirement), and then 89 percent scrubbing (80 percent removal requirement: cf. discussion in Chapter 2, Section 2.2).

Table 3-7

Cumulative Land Area Needed for Sludge Disposal, 1990-2000[a]

(square kilometers)

Scenario	Land Area	
M1.2(0)0.1	15.0	(5.8 mi^2)
M1.2(80)0.03	39.2	(15 mi^2)
M1.2(90)0.03	43.8	(17 mi^2)
H1.2(0)0.1	15.1	(5.8 mi^2)
H1.2(80)0.03	80.7	(31 mi^2)
H1.2(90)0.03	91.5	(35 mi^2)

[a] At a depth of nine meters (30 feet).

Table 3-8

Total Coal Ash Production

(Millions of metric tons)

Growth Rate	1990	1995	2000
moderate	61.9	68.1	74.9
high	73.5	101	135

Table 3-9

Water Consumed by FGD Systems

(Millions cubic meters per year)*

Scenario M1.2(0)0.1

Region	1990	1995	2000
NE	3.99	4.74	5.73
MA	26.5	28.5	31.6
SA	16.8	13.9	13.0
ENC	15.3	15.7	15.9
ESC	7.07	6.90	5.76
WNC	negligible	negligible	negligible
WSC	14.1	14.1	14.2
NM	6.26	6.80	6.61
SM	24.7	23.3	21.2
PA	negligible	negligible	negligible
Nation	115	114	114

Scenario M1.2(90)0.03

Region	1990	1995	2000
NE	4.73	5.48	6.63
MA	25.3	33.2	44.7
SA	47.0	64.7	80.5
ENC	20.1	19.3	16.8
ESC	5.54	6.86	7.52
WNC	7.13	13.2	23.6
WSC	72.1	111	133
NM	13.8	19.6	24.1
SM	40.7	37.1	38.5
PA	9.65	12.1	11.7
Nation	241	322	387

* One acre-foot = 1,234 cubic meters

Table 3-9 (continued)

Water Consumed by FGD Systems

(Millions cubic meters per year)*

Scenario H1.2(0)0.1

Region	1990	1995	2000
NE	4.65	8.04	14.7
MA	11.5	8.13	5.07
SA	18.0	14.2	15.3
ENC	17.0	36.0	59.8
ESC	1.13	0.348	0.106
WNC	negligible	negligible	negligible
WSC	13.9	14.2	14.2
NM	6.65	6.71	6.78
SM	24.6	22.6	20.7
PA	negligible	negligible	negligible
Nation	94.5	110	137

Scenario H1.2(90)0.03

Region	1990	1995	2000
NE	5.43	9.40	18.5
MA	39.7	75.0	105
SA	63.9	103	143
ENC	37.5	82.2	134
ESC	73.91	13.2	30.2
WNC	13.5	35.0	65.4
WSC	92.7	174	258
NM	19.9	31.8	42.3
SM	37.8	46.4	57.5
PA	22.2	36.6	71.9
Nation	337	607	927

* One acre foot = 1,234 cubic meters.

Table 3-9

Water Consumed by FGD Systems

(Millions cubic meters per year)*

Scenario H1.2(80)0.03			
Region	1990	1995	2000
NE	4.92	8.53	16.4
MA	32.9	64.7	91.8
SA	58.4	92.8	127
ENC	33.7	72.9	121
ESC	3.54	9.37	25.3
WNC	12.1	30.1	57.0
WSC	83.9	158	232
NM	17.5	27.8	37.1
WS	34.3	39.9	51.0
PA	17.8	32.0	63.6
Nation	299	534	823

* One acre foot = 1,234 cubic meters.

Whether or not the water demands shown in the table would constitute a significant impact on an area's water supplies of course depends on the region and locale within the region. Parts of the South and North Mountain areas and southern and central inland California are critical areas. However, it helps to put the FGD consumption quantities in perspective by comparing them with the other major consumptive use of water by power plants: condenser cooling. The rate of evaporation by generating plant cooling systems under scenario M1.2(90)0.03 is projected to be 6.84 million acre-feet per year by 2000 – twenty-two times the consumptive rate projected for scrubbers.

A final water use which the simulation model quantifies is the amount of highly polluted "black water" discharged by coal preparation plants which clean coal for sulfur removal. Based on the coal sulfur levels which were supplied to Teknekron for this study,[5] judgments were made as to which coals should be considered cleaned – tonnages of cleaned coal consumed varied from 29 percent of the total in the early years of the simulations to 11 percent in the later years with the revised NSPS in effect. Generally, a mandatory SO_2 removal of 80 percent or more discourages the use of cleaned coals: this effect is evident in the water data shown in Table 3-10. These data should not be considered definitive, however, because of the judgmental factors involved in labeling a coal cleaned or uncleaned. (For example, ICF, Inc., the EPA contractor who supplied the coal data for this study considers only about one percent of the coals to be "deep cleaned" for sulfur removal with the revised standards in effect.[5])

Table 3-10 Water Discharged by Coal Cleaning Plants in 1995*

(Millions cubic meters per year)

Coal Supply Region[a]	Scenario M1.2(0)0.1	Scenario M1.2(90)0.1
Appalachia	151	90.0
Midwest	70.5	67.4
Nation	221	157

[a] The coal supply regions are defined in more detail in Section 3.4.

* See cautionary note in text. One acre foot = 1,234 cubic meters.

3.5 ENERGY REQUIREMENTS

The energy requirements of FGD systems have two components: (1) the electrical power consumed in operating the system (between three and four percent for a 500 Mw unit with full scrubbing of a high sulfur coal); (2) fuel consumed in reheating the flue gas after scrubbing (done in cases where the gas is scrubbed to insure adequate plume dispersion and to prevent condensation and corrosion).[11] An indirect "penalty" also is incurred because of the reduction in net generating capability – approximately five percent for full scrubbing. This effect has been discussed in Chapter 2: data presented in this chapter address only the "direct" energy requirements.

Assumptions about scrubber energy demands are those developed by Pedco Environmental, Inc.[6] Steam is used for reheat on all units subject to current and revised new source standards. Units subject to SIP limits are assumed to require retrofit of the scrubber, and oil is used for reheat in these cases. (Oil is also used in operating the new mag-ox systems. The amount of energy consumed in both ways is small compared to the energy used for reheat on the newer units.)

Table 3–11 gives the energy consumed by FGD systems in 1995 for the 80 percent and 90 percent removal standard and the baseline cases, as well as the percentage of total coal energy consumed.

A second energy impact which could be significant if a revised standard resulted in large shifts in coal supplies is the change in the energy consumed by railroads and barges in transporting the coal.* A shift away from the use of western coal in the Midwest in favor of more local supplies, for example, would be expected to reduce coal transport energy.

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* A small amount of coal is also transported over short distances by trucks – this mode is ignored in our calculations.

Table 3-11

Energy Consumed by FGD Systems in 1995

Scenario	Energy Consumption for FGD (10^9 Megajoules)	Capacity Used for FGD (GW)	Fraction of Coal Energy for Generation
MI.2(0)0.1	187	3.68	0.95%
MI.2(80)0.03	534	10.5	2.7%
MI.2(90)0.03	588	11.6	3.0%
HI.2(0)0.1	214	4.21	0.71%
HI.2(80)0.03	944	18.6	3.1%
HI.2(90)0.03	1150	22.6	3.8%

The Utility Simulation Model estimates energy consumed in coal transport by assuming supply "nodes" (cities) in coal-supply regions and centrally located nodes (cities) in each consuming state. Rail and barge transport distances are then associated with each possible supply-demand nodal pair, using rail and barge routing maps. The coal supply regions used by Teknekron and the nodal cities are shown in Tables 3–12 and 3–13.

Calculations of fuel-energy consumed by rail and barge were made assuming the following modal energy intensities: rail = 366 Btu per ton-mile; barge = 296 Btu per ton-mile.[12] Results for the 90 percent control scenarios are shown in Table 3–14.

These results show a significant reduction in fuel consumed with imposition of the more stringent controls, due primarily to a shifting of demand away from western coals delivered to states bordering and east of the Mississippi River.[5] Note in particular that the energy savings in 1995, 50 10^9 MJ (4.7 10^{13} Btu) and 120 10^9 MJ (1.1 10^{14} Btu), serve to offset about 10 percent of the direct FGD energy requirements projected for that year (588 10^9 MJ and 1150 10^9 MJ) for moderate and high growth respectively.

Table 3-12

Teknekron Coal Supply Regions

Region	Coal Type	Symbol	States Encompassed	Nodal City
Northern Appalachia	bituminous	NA/B	OH,PA	Pittsburgh, PA
Central Appalachia	bituminous	CA/B	WV,VA,KY(east)	Charleston, WV
Southern Appalachia	bituminous	SA/B	TN,AL	Chattanooga, TN
Interior East	bituminous	IE/B	IL,IN,KY (west)	Mattown, IL
Interior West	bituminous	IW/B	IA,KS,MO,OK	Kansas City, MO
Northwest	subbituminous lignite	NW/SB NW/L	MT,ND MT,ND	Billings, MT Williston, ND
Central West	bituminous subbituminous	CB/B CB/SB	UT, CO WY	Grand Junction, CO Casper, WY
Southwest	subbituminous	SW/SB	AZ,NM	Gallup, NM
Texas	lignite	TX/L	TX	Palestine, TX

Table 3-13

Coal Demand Nodes

Consuming State	Nodal City	Consuming State	Nodal City
AL	Birmingham	NC	Raleigh
AR	Little Rock	ND	Bismark
AZ	Phoenix	NE	Lincoln
CA	Sacramento	NM	Concord
CO	Denver	NH	Trenton
CT	Hartford	NJ	Albuquerque
DL	Dover	NV	Carson City
FL	Orlando	NY	New York
GA	Atlanta	OH	Columbus
IA	Des Moines	OK	Oklahoma City
ID	Boise	OR	Salem
IL	Springfield	PA	Harrisburg
IN	Indianapolis	RI	Providence
KS	Topeka	SC	Columbus
KY	Frankfort	SD	Pierre
LA	Baton Rouge	TN	Nashville
MA	Boston	TX	Austin
MD/DC	D.C.	UT	Salt Lake City
ME	Augusta	VA	Richmond
MI	Lansing	VT	Montpeler
MN	Minneapolis	WA	Olympia
MO	Jefferson City	WI	Madison
MS	Jackson	WV	Charleston
MT	Billings	WY	Casper

Table 3-14

Energy Consumed in Transporting Coal to Electric Generating Plants

(10^9 Megajoules)

Year	Scenario M1.2(000.1	Scenario M1.2(900.1	Scenario H1.2(000.1	Scenario H1.2(00.1
1976	100	100	100	10
1990	250	230	370	30
1995	300	250	560	40
2000	350	260	780	50

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APPENDIX

DESCRIPTION OF TEKNEKRON'S ELECTRIC UTILITY SIMULATION MODEL AND ASSOCIATED DATA BASES

APPENDIX

TEKNEKRON'S ELECTRIC UTILITY SIMULATION MODEL AND ASSOCIATED DATA BASES

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I. MODEL DESCRIPTION

For the Environmental Protection Agency's review of New Source Performance Standards Teknekron has applied its Electric Utility Simulation Model. This section describes the components of that model and their integration into the overall model framework. Teknekron's Electric Utility Simulation Model examines the implications of investment and operating decisions made by electric utility firms as these decisions may be influenced by energy and environmental policies, technology choices, and economic conditions. These implications include forecasts by county for:

- **Capacity expansion**
- **Electricity generation**
- **Fuel consumption**
- **Pollutant generation**

and forecasts by state for various measures of economic and financial costs arising from each set of decisions.

This highly flexible model – developed and reviewed by experts in electric utility technology, operations, and regulation -- makes it possible to investigate the impacts of numerous alternative policies while coherently and consistently accounting for the many technical, economic, energy, and environmental factors that directly influence decisions made by utility companies.

Teknekron's Electric Utility Simulation Model consists of a number of interconnecting computer modules and data bases that simulate decisions for system planning and operation, utility finance, and the operation of individual technical processes. The model is driven by a set of exogenous scenario elements that include electricity demand levels, financial market conditions, fuel prices and availabilities, advanced technology deployment, and environmental regulations. For each scenario, the model calculates the following by geographical region (county or state) for future years up to 2010:

- **Factor demands, including**
  - fuel use, by type and by region of origin
  - electricity generated
  - capital requirements, by source (e.g., debt, common equity, preferred equity)
  - plant and equipment requirements
  - releases of air and water pollutants and generation of solid wastes
- **Financial statistics for utility firms**
- **Average electricity prices**

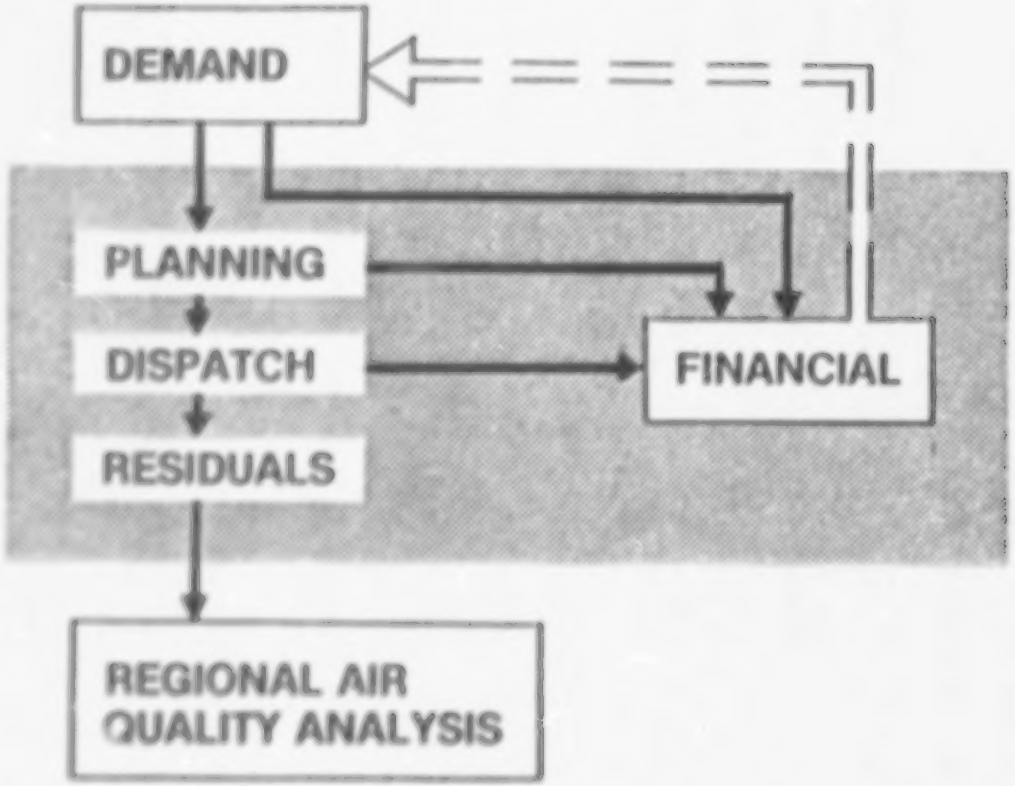
In order to produce these calculations at the required level of detail, the model considers generating unit sites located in each county where electricity is produced, fuel and water are consumed, and pollutants are released. Since utilities operate as integrated systems, the model presently simulates joint operation (i.e., dispatching) of all generating units within a state. Finally, the responses of utility firms to the external environment in which they function may be changed by the model user by modifying present data bases or specifying alternate choices for future system planning and system operation. For example, the particular scenarios evaluated in the New Source Performance Standards Review encompass a range of futures for electricity demand, fuel selection, choices of technology, and pollution control regulations as specified by the U.S. Environmental Protection Agency.

Figure 1 is a simplified diagram of Teknekron's Electric Utility Simulation Model. The model includes the following major components:

- **Demand projection, including**
  - retail and wholesale sales and purchases
  - energy generation, i.e., average load growth
  - peak load growth

Figure 1

TEXAS ELECTRIC UTILITY SIMULATION MODEL



- **System planning, including**
  - choice of generating unit type
  - choice of fuel type, quality, and region of origin
  - choice of pollution control technology
  - expansion of transmission and distribution networks
  - siting of generating units

- **Dispatch, including**
  - calculation of unit capacity factors for each typical day of operation, by class of unit
  - calculation of total fuel, operation, and maintenance expenses for electricity generation
  - projection of fuel consumption, by type and region of origin
  - pollution control costs and operating characteristics for the various types of pollution control devices

- **Financial, including**
  - integration of projected production expenses with construction expenditures
  - projection of the firm's balance sheet, income statement, sources and uses of funds, and other financial statistics
  - calculation of revenue requirements and electricity prices

- **Residuals, including**
  - projection of release rates at the generating unit site for numerous air and water pollutants and for solid wastes
  - projection of consumption of water and other resources

- **Regional Air Quality Analysis, including**
  - forecasts of counties having high emissions from utility and industrial boilers
  - analysis of historical meteorological data to yield preferred paths for downwind transport of emissions from source locations
  - analysis of emissions, air quality, and meteorological data to develop source-receptor relationships for SO_2 emissions and sulfate concentrations
  - application of air quality models to determine ambient concentrations of SO_2, NO_x, particulates, and sulfates

The following sections briefly describe the major components of the model and their associated data bases. Use of the model requires that a set of scenario elements be defined. These characterize the issues the user may wish to address, such as choice of fuel, pollution controls, siting, or the economic viability of alternative generation technologies.

COMPONENTS OF TEKNEKRON'S ELECTRIC UTILITY SIMULATION MODEL

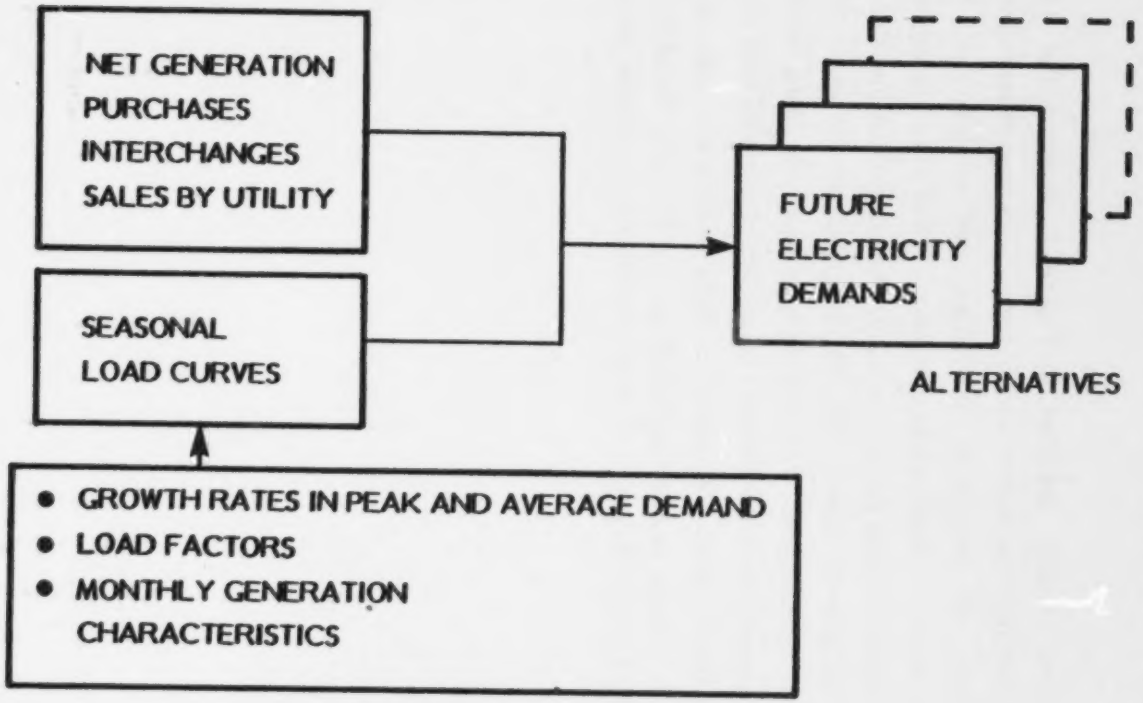
This section provides a summary description of each component of Teknekron's Electric Utility Simulation Model. The current version of the model operates on a geographical region equivalent to a state by treating all investor-owned firms and all non-investor-owned firms as two individual firms that own the assets owned by the actual companies in that state. System planning, dispatching, and financial simulations are carried out on a state basis separately for the two classes of firms. Simulations of residuals generation and resource consumption are carried out for generating units located at the county level. Thus, it is possible to forecast fuel consumption and pollutant release rates by county and economic impacts by state. Impacts are then aggregated to state, regional, and national levels.

A. DEMAND MODULE

The Demand module, depicted in Figure 2, projects the future electricity demands that must be met by utility firms. The module now uses 1975 base-year information, net generation, purchases, net interchanges, and retail and wholesale sales for each utility company. These data are aggregated to obtain state-by-state demands for both investor-owned and non-investor-owned utilities. Alternative growth rates may be specified to develop different demand projections for analysis. The module uses base-year data for load factors and monthly generation characteristics to construct seasonal load curves that can be varied in future years. A variety of data sources are used to determine each projection. These sources include Regional Electric Reliability Council forecasts, FPC Electric Power Statistics, and OBERS population projections.

Figure 2

DEMAND MODULE



B. SYSTEM PLANNING MODULE

The System Planning module, depicted in Figure 3, projects the composition of the state system; estimates construction requirements for generation, transmission, and distribution facilities; simulates fuel choice; and determines pollution-control needs in response to environmental regulation and the costs for alternate compliance strategies. Steam-generating facilities (both nuclear and fossil) are treated on a unit-by-unit basis. Nonsteam facilities are treated on an aggregated basis. Each utility system must be able to meet its peak demands with an adequate reserve margin, and the availabilities for its classes of generating units must allow the seasonal loads to be met.

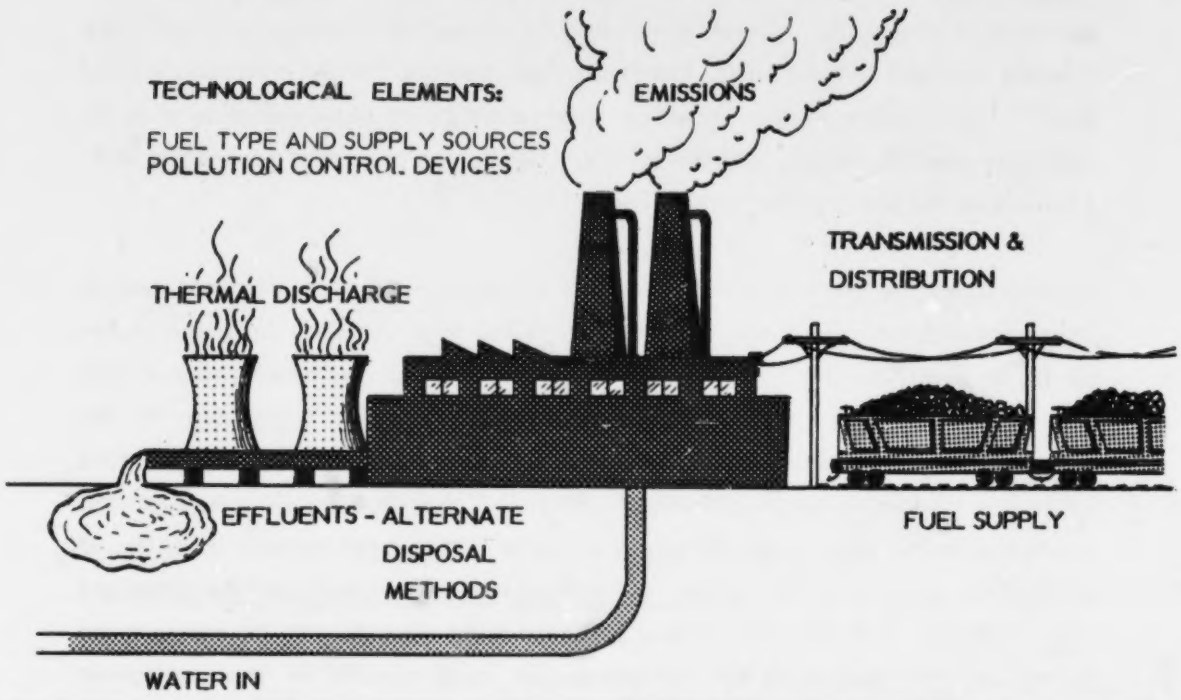
In simulating the composition of the state systems, the System Planning module uses announced plans of the individual utilities, aggregated to form the state-firms, on a unit-by-unit basis through 1985, the last year for which reliable data are available. For subsequent years it uses the utilities' projections of the composition of new additions, or it may vary additions by scenario. Announced units are treated as subject to modification in line with scenario specifications (higher or lower demand levels, higher or lower additions of nuclear capacity, of oil-fueled capacity, etc.). Units' fuel conversion, retirements, and reratings are also included. Future units beyond 1986 are sited according to county-specific siting weights developed by Teknekron for each county in the contiguous 48 states.

Since there is uncertainty about the relative growth rates of peak and average demand and about the impact of load management policies on hourly and seasonal loads, the System Planning module is able to change the shape of load curves by specifying separate growth rates for both peak and average demand.

Environmental regulations for air and water pollution represent both existing regulations and proposed levels of control -- for example, thermal and chemical controls for discharges to water, State Implementation Plans, New Source Performance Standards (NSPS), and Best Available Control Technology (BACT)

Figure 3

SYSTEM PLANNING MODULE



SCENARIO ELEMENTS: ENERGY POLICY
ENVIRONMENTAL POLICY
ECONOMIC CONDITIONS

PLANNING FOR COST-EFFECTIVE OPERATION

FUEL CHOICES AND SUPPLY SOURCE
GENERATING TECHNOLOGIES
REGULATIONS
PLANT CHARACTERISTICS

→ COSTS

air-emission limits. In accordance with scenario specifications, compliance schedules can be adjusted and various optional new levels of control may or may not be imposed. Fuels are selected from the available alternatives by considering a trade-off between premium-priced clean fuels, the costs of pre-combustion cleaning, and the costs of the different types of pollution controls necessary to utilize cheaper fuels and still comply with regulations. Pollution control costs are determined in detail on a unit-by-unit basis and include capital outlays, increased operating costs, and losses of capacity that make new construction necessary in order to maintain system performance. Detailed engineering process models and data bases are utilized. All costs are calculated as functions of fuel composition, plant characteristics, and the required level of pollution control.

To make these projections, the System Planning module requires a number of data bases. Some of these are:

- **Existing Steam Units.** Description of steam units in operation in the base year including ownership, county of location, capacity, age, fuel type, etc.

- **Announced Units.** Steam and nonsteam units announced as under construction, with their projected dates for coming on line. Also includes announced retirements and reratings.

- **Conversion Plans.** A number of alternative files of unit-by-unit conversion plans in response to possible modes of natural gas curtailment and conversion from oil.

- **System Data.** Extracts from FPC Form 1 and Form 1M and other sources for utility systems, merged to describe the aggregated state-firms. Included are data on existing non steam generating capacity; data on the operation and maintenance costs experienced for various classes of equipment; data on expenditures for transmission and distribution systems, matching energy and capacity growth; and data on general and administrative costs.

- **Construction Costs.** Costs for various types of capacity and schedules of expenditures.

- **Fuels Data Base.** Prices, sources, and physical and chemical properties of fuels used for electricity production in each state.

- **Thermal Controls Data Base.** For existing units and those under construction, estimates are given of the likelihood of exemption from forced conversion to closed-cycle cooling under thermal pollution-control regulations. For future units, estimates are also provided of the likely choices among cooling alternatives.

- **Unit Parameters.** Technical parameters to be used for steam units when data on a unit's specific technical characteristics are not available. These parameters are based on the most common characteristics for age and fuel class.

- **Future Capacity Mix.** Fractions representing the ratios of new coal, oil, nuclear, and combustion turbine capacity, etc., after 1985 in each state.

- **Siting Weights.** Weights for each county reflecting the relative likelihood of siting coal, mine-mouth coal, oil, gas, or nuclear steam units in the future in each county.

- **Emission Regulations.** Regulations and their year of application for air pollutants (primarily SO_2, NO_x, and particulates), including State Implementation Plans, New Source Performance Standards, and proposed Best Available Control Technology standards.

A number of sophisticated codes and computer subroutines contribute to the System Planning module. As examples, we describe briefly the Coal Assignment Model and three of its subroutines: the coal transportation cost model, the particulate control cost model, and the SO_2 control cost model. These are related primarily to the selection of coal supply and appropriate pollution control devices.

- **COAL ASSIGNMENT MODEL** (ASSIGN)

ASSIGN is an interactive program that finds the least-cost coal delivered to utility or industrial boilers in every state, subject to applicable sulfur dioxide and particulate emission limitations. The basic data are the properties and mine-mouth prices of coals from 11 major producing regions of the country; the costs and efficiency of physical coal cleaning; premiums associated with very low sulfur eastern coals; transportation routes, and cost algorithms for transportation of coal by barge, rail, and slurry pipeline. A "default" data base may be modified to incorporate user judgment or to examine the sensitivity of assumptions about such key data as coal prices, transport costs, pollution control costs, and coal characteristics.

The product is a list of coals, by state or point of end-use, that can be burned at least cost, including the cost of any emission controls required to comply with federal and state emission limitations. For example, results for power plants located near Harrisburgh, Pennsylvania, might show for one set of conditions that (a) the older generating units would burn local (Northern Appalachian) uncleaned coal costing 90 cents per million Btu delivered to the plant, (b) the newer units subject to New Source Performance Standards would burn Appalachian cleaned coal costing 140 cents per million Btu, and (c) the future units subject to BACT requirements would also use the local coals with flue gas scrubbing. Each coal is characterized by region of origin, delivered cost (in cents per million Btu and dollars per ton), and effective cost, which is the actual cost of burning the coal, including the annualized costs of pollution controls. Penalties associated with derating boilers designed for higher-rank coals are also included in the effective cost. In addition, the output indicates the emission limit that each category of boiler has to meet, the boiler's actual emissions, and, where scrubbing is the chosen option, the fraction of flue gas scrubbed in order to meet the limit. Other results of ASSIGN show how each selected coal would move from the mine or source region to the

consumer. These results for a specific set of assumptions, i.e., for a scenario, may be fed into the System Planning module for evaluation in our dynamic simulation model.

- **COAL TRANSPORTATION COST MODEL**

Teknekron's coal transportation cost model is structured to calculate coal transport costs from the 11 major U.S. coal-producing regions to each of the 48 contiguous states. The model can easily be modified to calculate coal transport costs from specific coal mines to specific boiler locations if that level of accuracy is required.

Within the model, coal can be transported by railroad, river barge, Great Lakes steamer, slurry pipelines, or any combination of the four modes of transport. Four railroad, ten water, and three pipeline tariffs are used in calculating transportation costs depending, for instance, on the river used for transport and whether or not coal is being carried upstream or downstream.

The coal transportation cost model is used in conjunction with our SO_2 Control Cost Model and our Particulate Control Cost Model to determine the most economic source of coal assuming compliance with emission control regulations.

- **SO_2 CONTROL TECHNOLOGY AND COST MODEL**

Teknekron's SO_2 Control Cost Model is structured to calculate capital costs, fixed operating costs, variable operating costs, and capacity penalties for limestone, lime, and magnesium oxide flue gas desulfurization (FGD) systems installed on new boilers or retrofitted onto existing boilers. The FGD systems are modular, with module sizes of between 100 and 150 MW each, except for systems of less than 100 MW. The model is able to calculate costs for FGD systems from 25 MW to over 1,000 MW in size. All systems of 100 MW or more include a spare module for added reliability.

Inputs required by the model include unit size and heat rate; coal properties (C, H, O, N, S, H_2O, ash, heating value); SO_2 emission limit (lb/MBtu or percentage removal); and year the FGD system is to be built. Model outputs include capacity penalties and costs escalated (in constant 1975 dollars) to the year the FGD system is to be built.

In calculating FGD system costs and penalties, the model considers both the gas flow rate and the quantity of SO_2 to be removed. This level of sophistication makes it possible, for instance, to compare FGD costs for the same coal at various emission limits, or to compare FGD costs for various coals with the same sulfur content but different heating values.

- **PARTICULATE CONTROL TECHNOLOGY AND COST MODEL**

Teknekron's Particulate Cost Model is structured to calculate capital costs, fixed operating costs, variable operating costs, and capacity penalties for hot-side electrostatic precipitators, cold-side electrostatic precipitators, and fabric filters installed on new boilers or retrofitted onto existing boilers. The model calculates the costs for each of three particulate control devices and selects the device having the lowest annual cost. The model is able to calculate costs for particulate control devices of between 25 MW and 1,000 MW in size.

Inputs required by the model include plant size; capacity factor; heat rate; coal properties (C, H, O, N, S, H_2O, ash, heating value); particulate emission limit; economic factors (capital recovery factor, electricity cost); and year the device is to be built. Model outputs include capacity penalties and costs escalated (in constant 1975 dollars) to the year the device is to be built.

In calculating electrostatic precipitator costs, the model considers the coal sulfur content, ash resistivity, and gas flow rate through the precipitator. Fabric filter costs are based primarily on gas flow rate alone. This level of sophistication, along with the ability to compare total annual costs and

select the most economical device, makes it possible, for instance, to select the most economic particulate control device for coals with differing sulfur contents.

C. DISPATCH MODULE

The function of the Dispatch module, depicted in Figure 4, is to allocate electricity production among the various generating facilities available. The allocation is performed on the basis of least cost, considering hourly loads for typical days, limitations on unit availability, and total energy output for the various types of facilities. In order to project hourly loads for future years, it is necessary to modify current load shapes to conform to projected load factors, and our dispatching algorithm allows this flexibility. For example, suppose the user wants to simulate the supply of electricity under a load management scenario in which peak demand grows more slowly than average demand. In this case, the daily load curve would become progressively flatter, and the dispatching algorithm would allocate an increasing portion of the energy production to the more efficient baseload units. For the New Source Performance Standards Review both peak and average demand were assumed to grow at the same growth rate.

As a result of the allocation of electricity production, capacity factors are calculated for each class of unit. Using unit heat rates, the Dispatch Module calculates fuel consumption, operation and maintenance costs, and production expenses and forwards these to the Financial Module. Although it is possible to treat the unit heat rate as a function of capacity factor, data requirements make it desirable to assign a single heat rate to each unit, varying the heat rate only with the age of the facility and the presence or absence of pollution control devices.

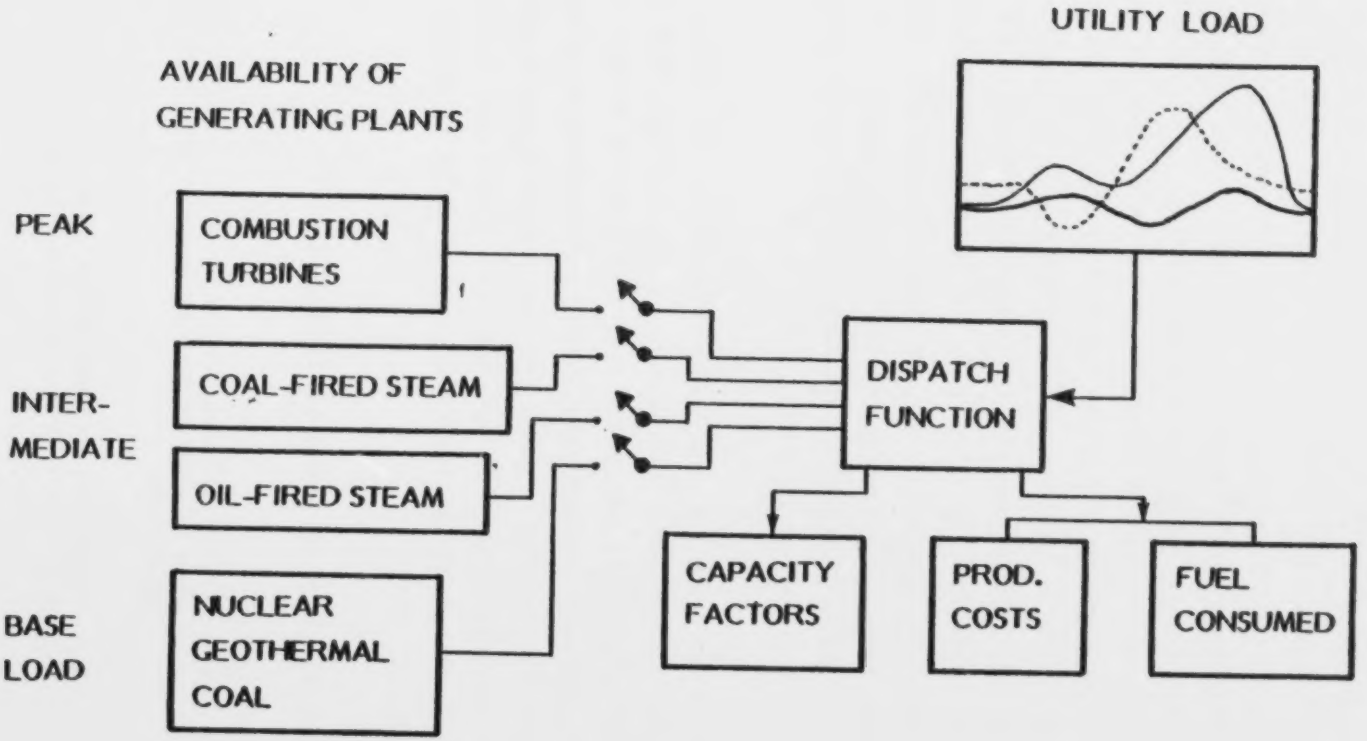
Two data bases are utilized by DISPATCH:

- Typical daily load curves for both week days and weekend days in each of two seasons for each public or private state firm.

- Generating unit availability, production limits, heat rates, and fuel and operation and maintenance costs.

Figure 4

DISPATCH MODULE

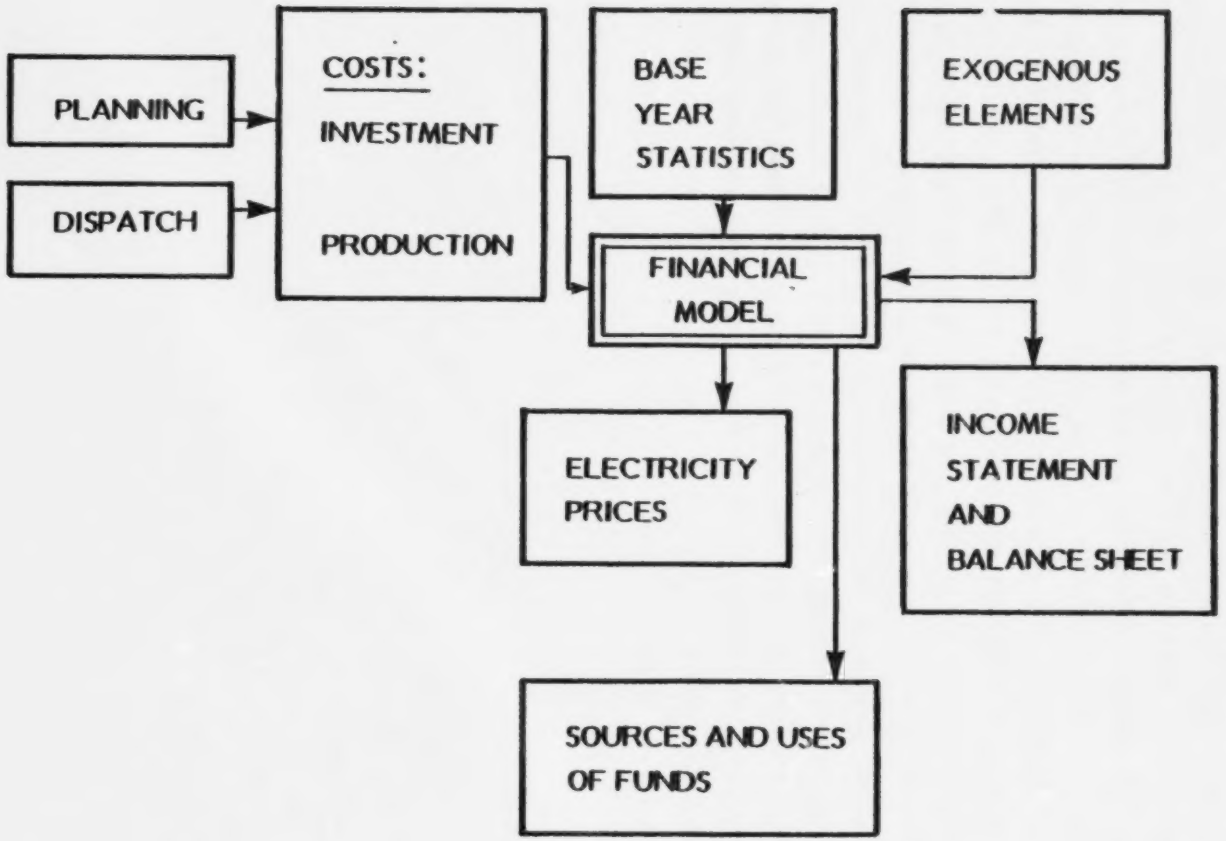


D. FINANCIAL MODULE

The Financial module, shown in Figure 5, simulates the financial performance of firms that are operating to meet consumer demands and incurring the operating expenses and costs of expansion and pollution control estimated by the Dispatch and System Planning modules. The data base required for FINANCIAL consists of the financial parameters for all the corporate entities being modeled. These parameters define initial financial conditions for the simulation, which proceeds by determining for each future year new prices, new needs for capital from external sources, new earnings levels, and the like, under projected regulatory constraints and tax policies. The term corporate entity refers to a single utility firm or group of firms whose assets and production facilities have been merged to the state level for the purpose of the simulation. Investor-owned and non-investor-owned firms are treated separately in the Financial module because of the fundamentally different financial structure of these two classes of firms and the dominant influence of financing costs and tax considerations in utility decision making.

Figure 5

FINANCIAL MODULE



E. RESIDUALS MODULE

The Residuals module, shown in Figure 6, receives the production levels from DISPATCH and associates them with individual units whose fuel choices and pollution control methods are projected by PLANNING. RESIDUALS then utilizes this association and its own data base in order to:

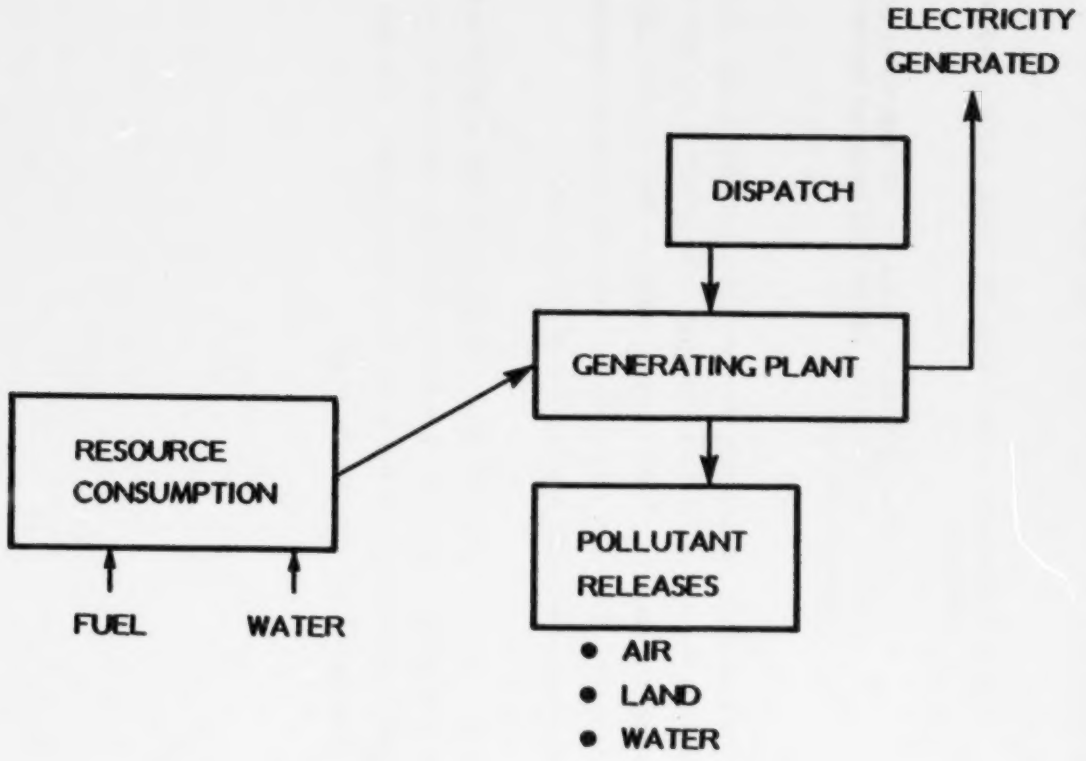
- Aggregate usage levels for fuels, water, and other resources.
- Determine production levels for air and water pollutants and for solid wastes, estimating seasonal emissions on a unit-by-unit basis.

The Residuals module employs two principal data bases. One is the same Fuels Data Base used in System Planning. The other is the file of generating units, sited by county. Fuel choice, capacity factor, and pollution controls then determine the level of residuals. Over 20 individual residuals, including trace metals and scrubber sludge, may be calculated.

The component modules described above provide a consistent framework for the examination of specific questions. Certain subroutines and submodels may be used independently of the entire simulation model. Changes to input parameters or assumptions can easily be made.

Figure 6

RESIDUALS MODULE



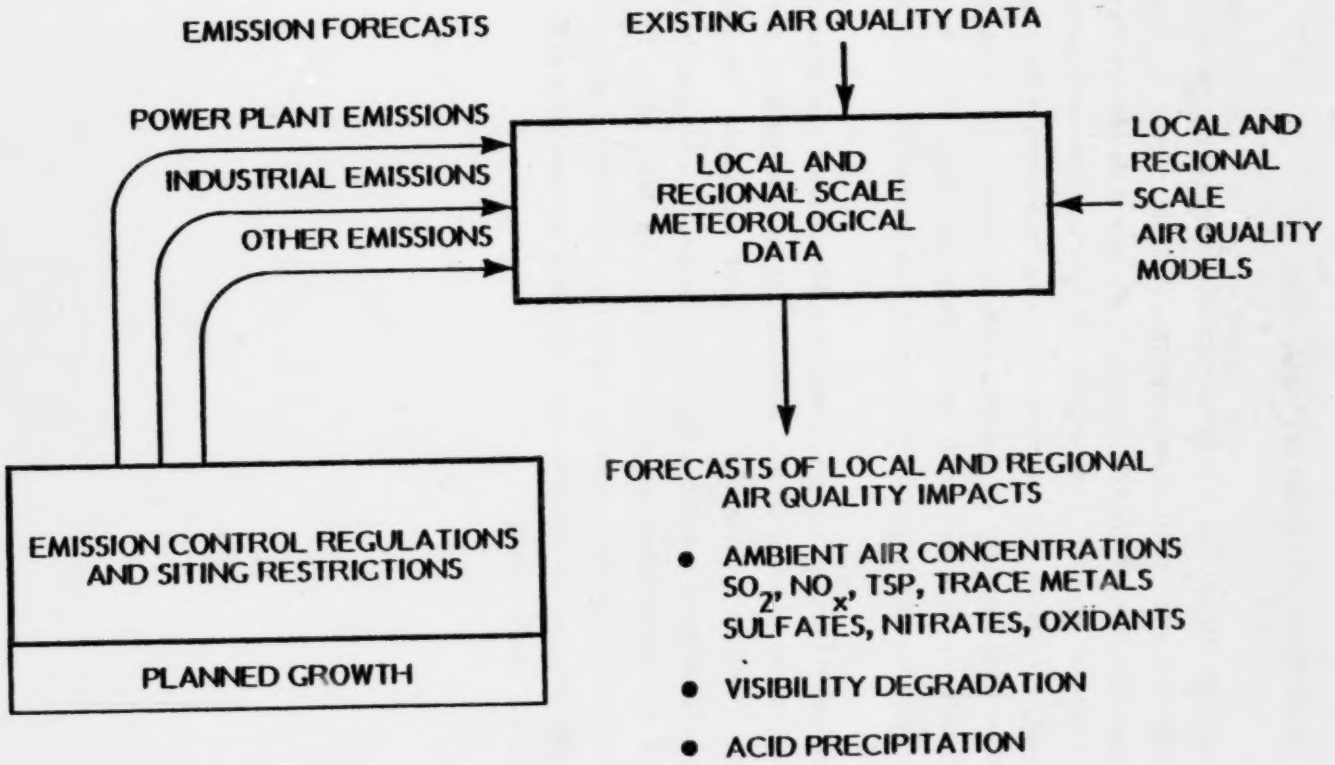
F. REGIONAL AIR QUALITY ANALYSIS

Teknekron's Integrated Assessment capabilities extend to air quality analysis. Our general approach is shown schematically in Figure 7. Emission forecasts provided by the Electric Utility Simulation Model determine those counties with high emission densities now and in the future. Meteorological analysis, using data gathered from many sources, allows us to determine the preferred paths for the downwind transport of the projected emissions. Teknekron's meteorological analyses have also identified the weather conditions likely to give rise to the long-range transport of pollutants and to high concentrations of sulfates.

Local and regional-scale air quality models predict the dispersion of airborne emissions and identify simple source-receptor relationships for specific pollutants. Previously a number of data bases and model capabilities have been applied to examine specific questions of air quality. Air quality impacts assessed so far include ambient air concentrations for SO_2, NO_x, TSP, trace metals, sulfates, nitrates, and oxidants; visibility degradation; and acid precipitation. For the New Source Performance Standards Review Volume III will discuss the air quality implications.

Figure 7

REGIONAL AIR QUALITY ANALYSIS


EMISSION FORECASTS
EXISTING AIR QUALITY DATA
POWER PLANT EMISSIONS
INDUSTRIAL EMISSIONS
OTHER EMISSIONS
LOCAL AND REGIONAL SCALE METEOROLOGICAL DATA
LOCAL AND REGIONAL SCALE AIR QUALITY MODELS
EMISSION CONTROL REGULATIONS AND SITING RESTRICTIONS
PLANNED GROWTH
FORECASTS OF LOCAL AND REGIONAL AIR QUALITY IMPACTS
• AMBIENT AIR CONCENTRATIONS SO_2, NO_x, TSP, TRACE METALS SULFATES, NITRATES, OXIDANTS
• VISIBILITY DEGRADATION
• ACID PRECIPITATION

2. DATA BASE DESCRIPTION

This section describes many of the data bases used by the Electric Utility Simulation Model. Where desirable, these data bases may be modified to accommodate new or more specific information. Drawing from many sources, Teknekron continually refines and updates the data.

A. DEMAND MODULE

DEMAND DATA — a file specifying net generation, purchases, net interchanges, retail and wholesale sales, pumped storage energy, and size (MW) of existing generating capacity, by individual utility company. These data are merged to describe the aggregated state firms.
Data Sources: "Statistics of Privately Owned Electric Utilities in the United States," and "Statistics of Publicly Owned Electric Utilities in the United States," for the year ending December 31, 1975, based on FPC Form I and Form IM magnetic tapes.

ANNUAL AVERAGE TO PEAK RATIOS — for each state firm, aggregate annual load factors derived from combined utility data submitted to the FPC. These load factors are used in calculating capacity needed and load duration curves for dispatching.

MONTHLY FRACTIONS — monthly peak loads as a fraction of the annual peak and the percentage of yearly energy generated in each month, by state. These data are used for seasonal load curves and dispatching.
Data Source: 1975 FPC Monthly Electric Power Statistics.

YEARLY GROWTH RATES — peak and average electricity demand growth rates in percent by year, either nationally, by Electric Reliability Council, or by state. These rates are specified by the user.

U.S. POPULATION PROJECTIONS — OBERS projections by state, by year.

CONTRACTS — interstate purchases or sales in future years in addition to those projected by **DEMAND**.

B. PLANNING-DISPATCH MODULE

EXISTING UNITS — a file of individual steam electric generating units as of December 31, 1975. Variables include name of the unit; state and county code; size (capability in MW); type of cooling; alternative fuel type capability; primary fuel type; date the unit came on line; and joint ownership data.
Principal Data Sources: "Steam Electric Air and Water Quality Control Data for the year ending December 31, 1975; Regional Reliability Council Reports; Electrical World Directories.

ANNOUNCED UNITS (Form 383-3) — a file of individual units (all generating types) for the period from 1976 to 1986 ("announced"). Variables include name of the unit; fuel type; size (MW); state and county of location; state of primary owner and percentage of ownership; year the unit will come on line; primary fuel type; and type of cooling.
Principal Data Sources: FPC published reports pursuant to FPC order 383-4 (Docket R-362), April 1, 1977; Regional Reliability Council Reports; and Electrical World Directories.

EXISTING UNITS (Forms 1, 1M) — a file containing the size (MW) of existing steam and nonsteam generating capacity. Includes operating and maintenance costs, asset value of transmission and distribution and general and administrative expenses (including intangibles), by individual utility firm. These data are merged to describe the aggregated state firms.

RERATES — a file of announced uprates, derates, and retirements as per FPC order 383-4 (Docket R-362), April 1, 1977.

CONVERSION — a file of orders to gas and oil burners to convert to coal as per FEA data (June 1977). The file also contains a schedule for curtailment of natural gas and substitute fuel planned on a unit-by-unit basis.

FUTURE MIX -- a file containing the generation mix, by state, of new units (coal, oil, nuclear, combined cycle, hydro, pumped storage, geothermal, combustion turbines, etc.) to be built after 1986. These may be varied by scenarios.

RESERVES -- a specified reserve margin is maintained throughout the simulation for each state.

PLANT MODEL PARAMETERS -- a file of the typical heat rate for each type of unit. The efficiency, heat rate, and type of particulate control mechanisms are defined as follows:

Year Unit Came on Line	Heat Rate	Particulates	
		Type	Efficiency
before 1950	12,500	Cyclone	50%
1950-1966	10,600	Cyclone	85%
1966 onwards	9,200	Precip.	As Required

FUEL COMPOSITION -- a file defining the composition of 19 kinds of coal from 11 supply regions, 4 kinds of residual oil, and 1 kind of gas. Each fuel is described as follows: by heating value, higher heating value, fractional enhancement of heating value (cleaned coals only), fractional weight yield from cleaning, ash content, sulfur content cleaned, sulfur content uncleaned, nitrogen content, carbon content, hydrogen content, moisture content, oxygen content. In addition trace element composition is provided for the following: Na, N, Ni, Sb, As, Ba, Be, B, Cd, Ca, Cl, Cr, Cu, F, Fe, Pb, Mg, Mn, Mo, Hg, Zn, Se, Ag, Ti, Tl. This file can be updated from the **ASSIGN** program.

FUEL USED -- a file of fossil fuels used, sulfur content, and prices, containing 6 kinds of coal and 4 kinds of oil available to each state. For this data set, 4

least-cost coals must be specified: a MET-SIP coal, a NON-MET-SIP coal, an NSPS-complying coal, and a BACT-complying coal. The coal (oil) sulfur content need not be sufficiently low to meet the applicable emission limit. If it is not, the **PLANNING** module will build a scrubber to reduce the emissions.

FUEL PRICES — a file specifying the delivered price of every fuel used (including coal, residual oil, distillate oil, natural gas, etc.), by state, in 1975 dollars. The file is updated from the **ASSIGN** program.

PRICE TRENDS — a file of price trends, excluding inflation, for coal, oil, gas, and nuclear fuels and for various types of construction for all years of the simulation.

CONSTRUCTION COSTS — typical construction costs for each type of electrical energy source.

COST SPREADS — a file specifying the spread of capital expenditures for each construction element (energy source, transmission, distribution).

WATER POLLUTION CONTROL REGULATIONS — chemical and thermal regulation parameters for water pollution control.

CUTOFF — a date by which retrofitting is determined. Plants operating before the date require retrofitting; plants operating after the date require no retrofitting.

DUE — date by which everyone must comply.

COMPLY — an integer defining the number of years before the date by which plants will begin to comply. The plants that comply are distributed evenly among the number of comply years.

OPDATE — similar to **CUTOFF**. This is an operational date to determine if a regulation will apply to a particular plant.

CHEMICAL CONTROL REGULATIONS

CHEM-CUTOFF: 1980
CHEM-DUE: 1977
CHEM-COMPLY: 2

MSCHEM REGS: MSCHEM is a more stringent chemical control scenario. Options are "T" (true) or "F" (false).

MSCHEM DUE: 1985
MSCHEM COMPLY: 5

THERMAL CONTROL REGULATIONS

THERM: Thermal controls
THERM-CUTOFF: 1980
THERM-DUE: 1981
THERM-COMPLY: 3

SIZES — simulated units derived from FUTURE after 1985 may be built according to the following sizes:

Nuclear	=	1200 MW
Coal	=	600 MW
Oil	=	600 MW

These may also be modified by the user.

HEAT BREAK — this parameter is used to determine whether the coal assigned to a unit is of high or low heating value, for the purpose of choosing a construction cost. **HEATBRK** = 9,600 Btu/lb.

SIP REGS — a file containing parameters pertaining to regulations for air pollution control scenarios.

SIP: State Implementation Plan

SIP-OPDATE: 1977

SIP-DUE: 1980

SIP-COMPLY: 4

NSPS LIMITS — an array containing New Source Performance Standards for SO_x, NO_x, and particulates on a national basis, measured in $\#/10^6$ Btu. These limits affect plant units coming on line on or after **SIP-OPDATE** above.

NSPS-SOX-COAL	1.2
NSPS-SOX-OIL	0.8
NSPS-SOX-GAS	0.1
NSPS-NOX-COAL	0.7
NSPS-NOX-OIL	0.3
NSPS-NOX-GAS	0.2
NSPS-PART-COAL	(Default is 0.1)
NSPS-PART-OIL	0.1
NSPS-PART-GAS	0.1

SIP-COAL — by state, current SIP emission rates allowed for SO_x, NO_x, and particulates, expressed in $\#/10^6$ Btu. Each pollutant has a stringent and less stringent limit depending on the location of the generating unit. Available are a list of current SIPs and a list of more stringent SIPs.

SIP-OIL — similar to coal.

BACT-SOX — Best Available Control Technology for SO_x control. Two plans are available.

PLAN 0: No regulations.

PLAN 1: Regulations as specified by BACT-SOX-MIN, BACT-SOX-LID below.

BACT-OPDATE: 1983

BACT-TSP-LIM: A particulate limit if Plan 1 is chosen. Specified by scenario. Currently $0.03\#/10^6$ Btu.

BACT-SOX-LID: Emission limit (#/10^6 Btu) not to be exceeded, even if SOX-MIN efficiency must be increased. Currently 1.2#/10^6 Btu.

MS NOX: A more stringent NO_x control scenario. Used if **MS-NOX-FLAG = T;** not used if **MS-NOX FLAG = F.**

MSNOX-ANNDATE: Announced date of this scenario. Currently 1980.

MSNOX-OPDATE: 1985

MSNOX-DUE: 1990

MSNOX-COMPLY: 4

MSNOX-BEFORE: #/10^6 Btu allowable before limits are imposed.

MSNOX-AFTER: #/10^6 Btu allowable after limits are imposed.

CONVERT $ — $/kW to convert oil and gas units to coal and oil ($65 and $5, respectively)..

THERMAL EXEMPTIONS — a file containing:

316A-RETRO: Percentages of existing plants that will not qualify for the compliance under 316(a), by state. These plants will need retrofitting.

EXEMPT: Number of plants that will qualify for exemption under 316(a).

ECON: Number of plants that will add cooling towers for economic and technical reasons.

POLL: Number of plants that will add cooling towers for pollution control reasons.

316A-NEW: A file containing percentages of new plants that will qualify for compliance under 316(a), by state. These plants will not need retrofitting.

Data Source: Appendix D of "Water Pollution Control for the Steam Electric Power Industry," for NCWQ, December 15, 1975, by Teknekron, Inc.

COUNTY — a file containing land-use data and EPA classification on a county-by-county basis for each of the 48 contiguous states. The following data are included:

1. County name and UTM coordinates.

2. Siting weights: site-specific economic and engineering assessment of the suitability of siting a new power plant in that county. Separate weights are provided for the following plant types: coal, mine-mouth coal, residual oil, nuclear.

3. The county's environmental status code vis-a-vis prevention of significant deterioration and attainment of ambient air quality standards.

DISPATCH STATE POINTERS — an array defining region of dispatch order for a state.

DISPATCH ORDER — the Dispatch Module utilizes its generation mix according to the Dispatch Order, a vector of ranks for N capacity classes. A least-cost dispatch order may be recalculated each year for each state.

DAILY MAXIMUM CAPACITY FACTORS — for each unit type, the capacity factor limits (i.e., the capacity factor that cannot be exceeded).

AVAILABILITY — the availability limit for each unit type. This limit constrains the capacity factor assignable for any hour of a typical day.

DAYSHAPES — a block data set containing normalized hour-by-hour dayshape curves, by state. Contains data for two seasons (summer and winter) and for all hours of the day. Monthly or seasonal peak and average are supplied by the Demand module. Weekends and weekdays are separately dispatched in both summer and winter seasons from load duration curves.

DEMAND-PLAN DATA — processed data passed from **DEMAND**. Includes peak demand and electrical energy to be generated, determined from retail sales, purchases, and wholesale sales. From monthly fractions, seasonal peak and average generation demands are passed through.

C. FINANCIAL MODULE

DEMAND-FINANCIAL DATA — includes **DEM-TO-FIN**, a file containing projections of Kwh sales (retail and wholesale) as generated by **DEMAND**, and **PLN-TO-FIN**, a file generated by **PLANNING** containing simulation values for:

1. Schedule of expenditures for plants coming on line in each year, by asset class
2. New additions to the construction work in progress account, by asset class
3. Expenses for nuclear fuel, fossil fuel, operation, maintenance, and pollution control O&M, by year

FINDATA — extracts from FPC Forms I and IM detailing data for the individual utility systems, merged to describe the aggregated state firms. Included are data on the operation and maintenance costs experienced for various classes of equipment; data on expenditures for transmission and distribution systems; and data on general and administrative costs.

BOOK DEPRECIATION

a. Steam Plant and Equipment, not including pollution control equipment: 35-year life; rate = .028571.
b. Nuclear Plant and Equipment, not including pollution control equipment: 30-year life; rate = .033333.
c. Hydro Plan and Equipment, not including pollution control equipment: 65-year life; rate = .015385.
d. Other Depreciable Assets: 30-year life; rate = .033333.
e. Transmission: 35-year life; rate = .028571.
f. Distribution: 25-year life; rate = .040000.
g. Pollution Control Equipment: 5-year life; rate = .200000.

TAX DEPRECIATION — All assets except pollution control equipment are depreciated using the Double Declining Balance Method. Pollution Control equipment is depreciated using the Straight Line Method over a 5-year life for both tax and book purposes.

a. Steam Plant and Equipment, not including pollution control equipment: 28-year life; rate = .035714.
b. Nuclear Plant and Equipment, not including pollution control equipment: 20-year life; rate = .050000.
c. Hydro Plant and Equipment, not including pollution control equipment: 50-year life; rate = .020000.
d. Other Depreciable Assets: 20-year life; rate = .050000.
e. Transmission: 30-year life; rate = .033333.
f. Distribution: 30-year life; rate = .033333.
g. Pollution Control Equipment: 5-year life; rate = .200000.

TAX RATES

a. Federal = .48
b. State = Varies by state, about .05

STOCK/DEBT FINANCING MIX

a. 50% Long-Term Debt
b. 15% Preferred Stock
c. 35% Common Stock

Common Stock "risk" factor over the bond rate = .04

Preferred Stock "risk" factor over the bond rate = .01

BOND RATES

	1976	1977	1978	1979	1980 on
Investor Utilities	.0867	.0856	.0886	.0849	.0884
Public Utilities	.0566	.0529	.0546	.0522	.0544

Inflation Rate (all years) = .055

Interest coverage ratio limit in public financing = 2.00

Debt service limit in public financing = 1.75

Rate of repayment of long-term debt = 0.04

Investment Tax Credit tax rate = 10%

Amortization rate = .033333

Coefficients of costs in rate base formula = .125

Construction work in progress interest rate (calculated endogenously)

100% of firms are assumed to "normalize" for tax depreciation and tax credit

Return on common equity = .13

Coefficient of operating expenses in formula for rate base = 0.125

Coefficient of income tax in formula for rate base = 0.06

Debt/Equity ratio limit = 0.65

D. RESIDUALS MODULE

PROJECTED SYSTEM – a file of steam units resulting from simulation ordered by state-year with dispatched capacity factors for 16 classes.

UNIT INFORMATION – year on line; size; FPC ID; owner state; location state; county; fuel; controlled SO_x, particulate, and NO_x emissions; control device and efficiency; applicable air pollution regulation limit; how unit entered system (EXISTING, ANNOUNCED, FUTURE); how sited; and other physical quantities related to pollution control.

FUEL – fuel composition data for coal, oil, and gas. Includes heating value; sulfur, moisture, and ash content, plus trace and radioactive elements, if any.

REGIONAL METEOROLOGICAL AND COOLING SYSTEM – region-specific coefficients used to calculate water consumed in evaporative cooling.

NONSTEAM HEAT RATES – heat rates for combustion turbines, combined cycle, and geothermal units.

TRANSPORT – coal transportation route miles for water, rail, slurry pipeline. Used in computing transportation energy consumed and in evaluating coal choices in ASSIGN.

E. AIR QUALITY MODELS AND DATA BASES

Teknekron's Meteorology Group uses a number of data bases and air quality models that together provide a powerful tool for integrated assessment. Outputs of the Electric Utility Simulation Model can be used in conjunction with these resources, which are listed below. The air quality data bases are categorized in terms of emissions, meteorology, air quality, and effects. The models are categorized as models of simple source-receptor relationships, as simple phenomenological models, and as advanced dispersion models.

EMISSIONS DATA BASES

1. National Emissions Data System (NEDS)-EPA
   a. 1972, by state and Air Quality Control Region
   b. 1973, by county, state, and Air Quality Control Region
   c. 1975, by county and source category. (This is the state of the art for NEDS. Teknekron assisted EPA in building this data base over the past summer.)
   d. State and local agencies
      i. Six Ohio River Basin states
      ii. Eight Rocky Mountain states
      iii. Ohio – used in EPA revision of SIP (August 1977)
   e. Special NO_x emissions tests results
2. Emissions Projections from Teknekron's Electric Utility Simulation Model
   a. Emissions by county and state, projected from 1976 to 2000.
3. Strategic Environmental Assessment System (SEAS) DOE/EPA
   a. National Energy Plan Scenarios
   b. NSPS Review scenarios

4. Master Industrial County Data Base DOE/EPA

   a. Existing Major Fuel-Burning Installations (MFBI)

   b. Planned Industrial Boilers – American Boiler Manufacturers Association (ABMA)

   c. County Siting Weights for Future Steam Electric Plants

   d. Class I and Nonattainment Status for Individual Counties

   e. Regional Coal Assessment Siting Weights

   f. Various Geographic Location Codes

METEOROLOGICAL DATA BASES

1. Inversion and Mixing Height Files – EPA (Holzworth)

   a. 1960-1964

   b. 1972-1976

   c. 1977-1978 – selected periods on order

2. TDF 14 Data for National Weather Service Stations

   a. 1948-1974 hourly and 3-hourly observations at more than 150 stations

   b. Stability Array (STAR) outputs from more than 150 stations

   c. Generalized Persistence (GPER) outputs from more than 150 stations

      i. Extreme-persistence cases for 22.5^{o} sectors

      ii. Extreme-persistence cases for 45^{o} sectors

3. Number/Format Data for Canadian Environment Service Stations

   a. 1966-1976 hourly observations at ten stations

   b. Stability Array (STAR) outputs from ten stations

c. Generalized Persistence (GPER) outputs from ten stations

i. Extreme-persistence cases for 22.5° sectors

ii. Extreme-persistence cases for 45° sectors

4. Special Data from Towers

a. Ten Sulfate Regional Experiment Locations, 4/74-3/75

b. Three TVA locations, 1974-1976

c. Fifteen locations in the Commonwealth of Pennsylvania, 1975

d. Thirteen locations in the Rocky Mountain Region (EPA Region VIII)

AIR QUALITY DATA BASES

1. National Air Sampling Network (NASN), 1960 – present, at more than 100 selected locations

a. Sulfur Dioxide

b. Sulfates

c. Total Suspended Particulates

2. TVA Regional Trends Network, 5 stations, 1973-1976

3. Annual Monitoring and Trends Analysis Reports, EPA, 1970-1975

4. Trace Metals, EPA, 1965-1974

5. Sulfate Regional Experiment, EPRI

a. 4/74-3/75

b. 1977-1978 on order

6. Canadian Atmospheric Environment Service Intensive Sulfate Study, August 1976

7. American Electric Power, 10 networks, 1974-1976, on order

EFFECTS DATA BASES

1. Atmospheric Turbidity, EPA (Flowers), 1960-1975
2. Visibility (visual range), 1948-1976; for 150 locations, noontime visual range and relative humidities
3. Precipitation chemistry (acid rain)
   a. World Meteorological Organization, 1972-1975
   b. Canadian Atmospheric Environment Service Intensive Sulfate Study, August 1976

AIR QUALITY MODELS

1. Simple source-receptor relationships – developed and applied to areas where:
   a. emission data are plentiful and emissions can be ascribed to a predominant source category (e.g., power plants or industrial facilities)
   b. air quality data are plentiful for primary (i.e., SO_2) and/or secondary (i.e., SO_4) pollutants and are relatively free from local source influences
   c. meteorological data are plentiful and the results of analysis provide a convincing link between (a) and (b) above in terms of prevailing winds, most frequent extreme-persistence sectors, etc.
   d. the time periods and areas satisfying (a)-(c) above are, respectively, long (i.e., annual) and large (i.e., several air quality control regions)
2. Simple phenomonological models
   a. EPA Users Network for Applied Modeling of Air Pollution (UNAMP) interactive computer terminal
   b. Teknekron Sector Box Model with Source Intensification (SBSI)

3. Advanced dispersion models

   a. EPA Single Source (CRSTER) and Valley Models

   b. Teknekron Pseudo Spectral Three-dimensional Grid Model for Regional Sulfates (in preparation)